San Diego Gas & Electric Company

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TO5 – Cycle 1

Testimony of SDG&E Witnesses (Dane A. Watson, Joel Dumas, Dr. Roger Morin, Don Widjaja)

October 30, 2018

Docket No. ER19-_ __-___

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Exhibit No. SD-0014

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER19-__-000

PREPARED DIRECT TESTIMONY OF

DANE A. WATSON

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

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PREPARED DIRECT TESTIMONY OF

DANE A. WATSON

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Dane A. Watson. I am a Partner of Alliance Consulting Group, which provides consulting and expert services to the utility industry. My business address is 101 E. Park Blvd., Suite 220, Plano, Texas 75074.

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a Master's Degree in Business Administration from Amberton University. Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation, and certain accounting-related studies for clients in various industries. My duties related to depreciation studies include (1) assembling and analyzing historical and simulated data, (2) conducting field reviews, (3) determining service life and net salvage estimates, (4) calculating annual depreciation, (5) presenting recommended depreciation rates to utility management for its consideration, and (6) supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities Electric Company and successor companies ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities. My accounting responsibilities as Manager of Property Accounting Services included ensuring the corporation followed Generally Accepted Accounting Principles ("GAAP") and the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts as it related to, among other areas, the accounting for fixed asset capitalization, retirements and related depreciation reserve transactions, in addition to supporting that compliance before Internal and External Auditors and State Commissions.

I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I am a Registered Professional Engineer ("PE") in the State of Texas and a Certified Depreciation Professional ("CDP"). I am a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") and have held numerous offices on the Executive Board of the Dallas Section, Region and Worldwide offices of IEEE. I have twice served as President of the Society of Depreciation Professionals most recently in 2015. I also teach depreciation seminars on an annual basis for EEI and the American Gas Association (both basic and advanced levels), and I developed and teach the advanced training for the Society of Depreciation Professionals and other venues.

Q. Have you previously provided testimony?

A. Yes. In my 33-year career, I have testified in more than 170 proceedings before approximately 35 regulatory commissions across the United States. I have presented expert testimony before FERC on behalf of Florida Gas Transmission

Company, LLC in Docket Nos. RP10-21 and RP15-101; Granite State Gas Transmission, Inc. in Docket No. RP10-896; American Transmission Company, LLC in Docket Nos. ER12-212, ER17-191, and ER17-1664; Progress Energy-Carolina in Docket No. ER13-1313; Sea Robin Pipeline Company, LLC in Docket No. RP14-247; Northeast Transmission Development, LLC in Docket No. ER16-563; KOT Transmission in Docket No. RP16-097; Alabama Power Company in Docket No. ER16-2312; SEGCO in Docket No. ER16-2313; New York Power Authority in Docket No. ER17-1010-000; and Consumers Energy in Docket No. ER18-56-000. I also appeared in FERC Docket No. RM02-7 as an industry panelist on asset retirement obligations. A listing of the various proceedings in which I have appeared is provided in Exhibit No. SD-0015.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony of your testimony?

A. The purpose of my testimony is to support SDG&E's TO5 Formula rate filing before the FERC by: (1) describing the methods I used to determine the life and net salvage characteristics of SDG&E's plant accounts (2) presenting the results of the average service life ("ASL"), Iowa curves, and future net salvage ("FNS") analyses, and (3) support the resulting annual depreciation accrual expense and rate calculations performed as part of the depreciation study I conducted for SDG&E Electric Transmission Plant in this TO5 Formula rate filing.

Q. Other than your testimony, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring two exhibits in this case. Exhibit No. SD-0015 is a listing of cases in which I have provided testimony. Exhibit No. SD-0016 presents a description and the results of the comprehensive depreciation study performed by the Alliance Consulting Group in 2018 for SDG&E's depreciable transmission plant, as of December 31, 2017. That exhibit does not include rates for general or common plant.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

III. EXECUTIVE SUMMARY

Q. Please summarize the key components of your testimony.

A. The key components of my testimony include the following:

- I recommend that the Commission approve the depreciation rates developed for SDG&E's TO5 electric transmission plant accounts as set forth in Table 1 below, and as shown in Exhibit No. SD-0016 Depreciation Rate Study ("Depreciation Study"), Appendix A. These rates result in an annual depreciation expense accrual of $165.4 million as shown below.
- I support the increase in the annual depreciation expense for SDG&E's electric utility assets of approximately $19.6 million per year. This amount was determined by comparing the depreciation expense calculated by the current (approved) depreciation rates and the proposed depreciation rates at December 31, 2017. This comparison is shown in detail by account in Appendix B of the Depreciation Study. The study also provides the calculated overall composite rate of 3.12% at December 31, 2017 using these parameters.

- I explain the standard depreciation processes and methods, followed in the study, to determine SDG&E's proposed depreciation parameters for each FERC Uniform System of Accounts ("USoA") account. The depreciation study performs life and net salvage analyses from SDG&E's historical database to assist in making appropriate recommendations for each account. The parameter recommendations consist of an average service live ("ASL"), the appropriate Iowa curve, and the net salvage factor all based upon the analyses, interviews with SDG&E personnel, and expert judgment as part of the depreciation study I performed. Consistent with the prior studies and filings, my study combined the subaccounts into the primary FERC account for life and net salvage analysis. This provides one ASL, curve, and net salvage factor recommendation to be applied to each respective subaccount within an account.
- Table 1 below displays the proposed TO5 depreciation expense and rates by account.

TABLE 1

Proposed TO5 Account Rates and Expense
Depreciation Study as of December 31, 2017

Account	Description	Plant Balance $	Proposed Rates %	Proposed Expense $
E0135210	Struct & Imprv-Other	$ 380,765,072	2.37%	$ 9,031,722
E0135220	Struct & Imprv-SWPL	14,828,569	2.18%	323,399
E0135260	Struct & Imprv-SRPL	121,020,368	2.41%	2,918,746
E0135310	Station Equip.-Other	1,222,846,732	3.61%	44,141,636
E0135320	Station Equip.-SWPL	272,105,465	3.62%	9,841,219
E0135340	Station Equip.-Palomar	1,420,393	3.76%	53,425
E0135360	Station Equip.-SRPL	161,967,663	3.59%	5,820,517
E0135410	Towers & Fxtrs-Other	68,964,896	2.87%	1,979,269
E0135420	Towers & Fxtrs-SWPL	62,015,338	2.71%	1,678,922
E0135460	Towers & Fxtrs-SRPL	766,332,063	2.96%	22,682,708
E0135510	Poles & Fxtrs-Other	526,506,752	4.57%	24,074,930
E0135520	Poles & Fxtrs-SWPL	10,308,506	3.40%	350,175
E0135560	Poles & Fxtrs-SRPL	3,343,704	4.51%	150,735
E0135610	Ovrhd Cnd & Dev-Other	399,874,653	3.28%	13,126,643
E0135620	Ovrhd Cnd & Dev-SWPL	46,248,992	1.63%	754,619
E0135660	Ovrhd Cnd & Dev-SRPL	173,392,337	3.45%	5,980,306
E0135700	Trans UG Conduit	280,352,906	2.43%	6,805,948
E0135760	UG Conduit-SRPL	80,502,078	2.47%	1,990,531
E0135800	Trans UG Conductor	264,166,329	2.13%	5,627,323
E0135860	UG Cond. & Dev-SRPL	126,452,463	2.19%	2,765,065
E0135910	Roads & Trails-Other	83,139,884	1.69%	1,401,130
E0135920	Roads & Trails-SWPL	5,323,946	1.51%	80,579
E0135960	Roads & Trails-SRPL	227,675,967	1.66%	3,784,498
	Total	**$ 5,299,555,074**	**3.12%**	**$ 165,364,044**

IV. DEPRECIATION AND THE DEPRECIATION STUDY

Q. Please define "depreciation."

A. The Commission's Uniform System of Accounts defines depreciation as "the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities." 18 C.F.R. Part 101, *Definition*, No. 12.

Q. What is the purpose of depreciation?

A. Depreciation expense is an annual charge to reflect the declining remaining life of each asset over time. SDG&E conducts its accounting consistent with the Commission's Uniform System of Accounts. Each group of like-kind assets identified in the Commission's 300 series plant subaccounts is assigned an expected total average service life reflecting the total expected operating life of the asset group. Over time, depreciation expense accumulates in a reserve account such that at the end of its useful life, all amounts have been recovered and the asset's net book value is zero, giving consideration to net salvage. Once an asset's useful life has been exhausted, it is retired with the plant account credited and accumulated depreciation account debited. Any salvage and costs to retire the assets are also recorded in the accumulated depreciation account.

Q. Is the depreciation methodology you used a prescribed method to calculate and determine depreciation rates?

A. Yes. The depreciation rates proposed for SDG&E are calculated in accordance with FERC guidelines and Standard Practice U-4. I used the straight-line, Average Life Group (Broad Group) ("ALG"), remaining-life depreciation system to calculate annual and accrue depreciation in the study. The straight-line method prorates the recovery of service value in equal annual amounts. The ALG procedure (the most widely used in the utility industry) groups assets in categories (typically plant accounts and/or subaccounts) and depreciates all assets as if they had identical mortality characteristics, while using a single depreciation rate for the entire account. The ALG procedure also assumes that under-accruals resulting from early retirements are offset by over-accruals on assets that outlive the average service life. The remaining life technique accrues unrecovered service value over the average remaining life of the group. The remaining life technique adjusts for any under or over accruals that may have occurred. The system being used to calculate the TO5 Formula rates is reasonable, widely accepted in the industry and its regulators, and is the same accepted methodology used in past depreciation studies and approved in SDG&E's TO4 Formula filing Docket No. ER13-941-000.

Q. How did you calculate the proposed depreciation expense using this system?

A. After an average service life, dispersion, and net salvage are selected for each account, the life parameters are used to estimate what portion of the surviving investment of each vintage is expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ALG is defined by each group's respective account dispersion, life, and salvage estimates. A straight-line rate for each ALG is calculated by computing a composite remaining life for each group across all vintages within the group, dividing the remaining investment to be recovered by the remaining life to find the annual depreciation expense and then dividing the annual depreciation expense by the surviving investment. The resulting rate for each account using the ALG procedure is designed to recover all retirements less net salvage when the last unit retires. The ALG procedure recovers net estimated book cost over the life of each account by averaging many components.

Q. How is the remaining life annual accrual for each FERC account calculated?

A. The remaining life annual accruals are calculated for each plant account as follows:

(plant balance - future net salvage - reserve) / (average remaining life)

- Plant balance is the original installed cost of the assets, less any contributions in aid of construction.
- The future net salvage is the projected gross salvage for recovered materials less costs associated with retiring the assets. The future net salvage is calculated by applying the net salvage rate to the surviving plant balance (that plant yet to be retired).
- The reserve is the accumulation, since the inception of the plant account, of the following booked entries: depreciation accruals, plus salvage, less cost of removal, less the retirements, plus or minus any transfers in or out as provided for by the USoA.
- The average remaining life is the future expected service in years of the survivors at a given age. At any given age, the average remaining life is the unrealized life divided by the proportion surviving at that age.

Q. What is the date of your proposed depreciation rate computation?

A. SDG&E's proposed depreciation rates are computed using plant and accumulated depreciation as of December 31, 2017.

Q. Why did you choose that date?

A. The study date of December 31, 2017 contains the most recent fiscal year end plant and reserve information.

Q. Can you explain the process you followed to conduct your depreciation study in order to calculate the ALG depreciation rates being proposed in SDG&E's TO5 filing?

A. Yes. The depreciation study is performed in the following four phases:

1. **Data collection** consists of obtaining and reviewing SDG&E's historical data base of recorded transactions. This database is then used to perform individual account life and net salvage analysis.

2. **Analysis** consists of using statistical models to perform the actuarial life analysis. The actuarial method was performed on all accounts where sufficient history was available. In the case of SDG&E subaccounts of the same FERC account class were combined and analyzed together. For the net salvage analysis an individual account and combined account were performed. The assets in each subaccount are similar and provided a larger database for analysis. One life and net salvage recommendation is made and applied to all the subaccounts of the same FERC account. This is consistent with the past studies.

3. **Evaluation** consists of reviewing the results from the life and net salvage analysis. I also conducted interviews and site visits with SDG&E

personnel. The discussions with SDG&E personnel provide me the opportunity to learn first-hand what is happening from an operations view and their expectations and plans for the future. This phase brings together the past, current and future pieces to assist in making the best estimate of life and net salvage parameters for use in the calculation of depreciation rates.

4. **Calculation** is applying the life and net salvage recommendations, using the ALG procedure and remaining life technique, to each subaccount plant balance and reserve balance at the December 31, 2017 study date.

A more detailed discussion of the process I followed to conduct the depreciation study can be found in Exhibit No. SD-0016.

Q. What analyses did you conduct with the plant accounting database provided to you by SDG&E?

A. As part of the Depreciation Study, I conducted a statistical life study, a net salvage analysis, and an analysis of recorded depreciation reserves for all SDG&E's plant and equipment. SDG&E maintains its plant accounting records according to the USoA. For life analysis, SDG&E maintains vintage (aged data) plant accounting records by plant subaccount for assets in service. They also maintain depreciation reserves at the subaccount level with gross salvage and cost of removal recorded at the same level from 1991 to 2017. However, consistent with the prior studies, the subaccounts were combined into the major FERC account for life and net salvage analysis.

Q. Please explain the life analyses you conducted.

A. The life analyses I performed is referred to as the retirement rate (actuarial) method since SDG&E maintains what is referred to as aged data. This means it tracks the year an asset was placed in service and year in which it is retired, it records the vintage year of the asset along with the year it is retired. This aged data is used in the study to perform an actuarial analysis to assist in making average service life and dispersion recommendations. This approach to life analysis was performed at the major FERC account level (combining respective subaccounts) for a single account analysis that has the historical detail and retirement history necessary to support a thorough life study. If there is not enough historical detail, additional consideration is given to information provided during interviews with SDG&E operations personnel, similarity and use of assets of other utilities, and expert judgment. Table 2 below and Appendix C of Exhibit No. SD-0016 provides a comparison of the approved life and the proposed life by account.

Q. Please explain net salvage, the net salvage percentage, and why it is a component of depreciation expense?

A. Net salvage is gross salvage less the costs incurred to retire the assets (removal cost). If the salvage exceeds the removal costs, net salvage is considered positive. When the removal costs exceed salvage, net salvage is considered negative. The effect of net salvage, whether positive or negative, must be considered in the calculation of depreciation. A net salvage percentage is designed to recover the removal costs expected to be incurred at the end of an asset's useful life, where such costs will often exceed the asset's salvage value. The expected net salvage percentage is applied as a portion of depreciation expense such that, over the life of the asset, all expected costs to operate and remove the asset (net of salvage proceeds) are recovered from the customers who received the benefit of the asset's service.

Q. Is there any authoritative guidance on determining net salvage percentages?

A. Yes. One of the most widely used publications on depreciation comes from the NARUC publication, *Public Utility Depreciation Practices*, which states "salvage and cost of removal analysis involves the determination of salvage and cost of removal as a percentage of the cost of the retired property." In this study it is referred to as a future net salvage factor or rate ("FNS").

Q. How many regulatory commissions handle salvage and cost of removal as a component of the depreciation rate?

A. Historically, the majority of the regulatory commissions, including the FERC, have required that both gross salvage and the cost of removal be reflected in depreciation rates. The theory behind this requirement is that physical plant placed in service can have some residual value at the time of its retirement, so the original cost recovered through depreciation should be reduced by that amount. Likewise, there can be additional costs at retirement to remove and dispose of these assets that should be borne by the ratepayer receiving the benefit or service from the assets. The cost to retire is becoming more predominant over time for the industry and is specifically present for SDG&E in both the past TO4 Formula and continues in this TO5 Formula.

Q. How does the handling of salvage and cost of removal in this manner affect the utility customers?

A. There are two closely regarded principles that support the inclusion of net salvage in regulated utility depreciation rates: (1) the accounting principle that revenues be matched with costs, and (2) the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, known as "intergenerational equity."

Q. Can you please explain the regulatory concept of intergenerational equity?

A. Yes. The regulatory concept of intergenerational equity applied to net salvage is to assign costs for assets to the customers who have been served by those assets, no more and no less. The application of these principles requires that the estimated salvage and cost of removal of plant be recovered over its ASL.[1]

Q. What happens when property is retired and there is both positive salvage and cost to remove the assets?

A. NARUC also adds that when property is retired,[2] the effect of both salvage and removal costs are involved. The effect of net salvage, whether positive or negative, must be considered in the calculation of depreciation.

Q. How does this all come together in the current SDG&E historical analysis of net salvage?

A. In this depreciation study, net salvage factors (gross salvage less cost of removal as a percentage of retired plant cost) are proposed for SDG&E by analyzing

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[1] *Public Utility Depreciation Practices*, NARUC, August 1996, p. 157.

[2] *Public Utility Depreciation Practices*, NARUC, August 1996, p. 18," Salvage Considerations"

historical data from 1991 through 2017. The analysis uses moving averages for a period of two to fifteen year bands to assist in determining trends over a period of years and allow for all the costs for projects of a long duration to be recorded.

Q. Is this historical analysis a recognized approach to determine net salvage?

A. Yes. With respect to SDG&E, this approach is specified in the Standard Practice U-4 and recognized by NARUC, as cited above.

Q. Has there been a trend over time emerging from the recent SDG&E FNS analysis?

A. Yes. The prevailing trend in SDG&E's FNS analysis is towards more negative net salvage factors. The proposed net salvage is expressed as a percentage of the original historical cost[3] of the associated retirement (a constant), and the current pattern being experienced at SDG&E are increasingly negative net salvage factors. Thus, while there may be a lengthening in life (ASL extension) that decreases annual depreciation expense, any increase in a negative net salvage factor will increase the depreciation expense.

Q. Is the historical cost of both positive salvage and removal activity available for review and analysis?

A. Yes. SDG&E's recorded net salvage activity from 1991-2017 was used to perform the analysis. Based on the analysis, the SDG&E's overall net salvage being proposed in this TO5 filing is conservative in many of the accounts.

[3] The future net salvage parameter is expressed as a percentage of the original historical cost because the ultimate depreciation rate is applied to the historical cost of surviving plant. All values (plant cost, cost of removal, gross salvage, and reserve) used in the depreciation rate computations are nominal dollars.

Q. Is the net salvage analysis for the TO5 Formula included in your testimony by FERC account?

A. Yes. The specific TO5 FERC account's net salvage is included in an account-by-account discussion in my Exhibit No. SD-0016. Appendix D of that exhibit provides the historical analysis by account.

Q. Please briefly explain the net salvage reflected in the TO5 filing.

A. In this study, an analysis was performed for each major FERC account where there was historical retirement, salvage and cost of removal activity. Consistent with the TO4 filing, a combined analysis was performed so a net salvage factor could be determined and applied to similar subaccounts. This combined analysis provides a sound basis to apply a net salvage factor to all subaccounts, including the Sunrise Power Link accounts that were previously set at 0 percent based on the settlement in TO4.

Q. How does the Sunrise Power Link net salvage impact the depreciation rates in this TO5 Formula?

A. It has a significant impact. In the approved TO4 Formula, which I understand resulted from a settlement agreement, the net salvage value for the Sunrise Power Link accounts' was set at zero percent, which was not consistent with the net salvage treatment for comparable transmission assets. In this TO5 filing, as was done in the past, a combined analysis and recommendation is applied to each subaccount. The assets within each subaccount of each FERC account are similar assets, and the merging of the subaccounts within each FERC account is appropriate and beneficial in understanding the depreciation parameters of all assets within the FERC account. Other than the settlement, there is no valid reason, from a depreciation analysis perspective that the Sunrise Power Link transmission assets should have a zero percent net salvage while the same type of assets within other SDGE transmission subaccounts exhibit negative net salvage and have approved negative values. In certain Sunrise Power Link accounts, the net salvage factor moved from zero percent to a negative 10, 45, 75 or 100 percent to match the characteristics for other subaccounts within each FERC account. The increase in depreciation expense in the TO5 Formula compared to the approved TO4 Formula is nearly all due to the inclusion of net salvage for Sunrise Power Link accounts.

Q. Are the net salvage recommendations you propose conservative relative to SDG&E's actual history?

A. Yes. As is discussed in greater detail in Exhibit No. SD-0016, even the 15-year average negative net salvage indications for all accounts are more negative than the existing FNS factors. But only substation accounts were adjusted incrementally in this study. Please see Exhibit No. SD-0016, Appendix D for the net salvage analysis by account. Appendix C of Exhibit No. SD-0016 provides a comparison of the approved net salvage and the proposed net salvage by account.

Q. What are the depreciation parameters you propose to use in the calculation of depreciation rates for the TO5 accounts?

A. Table 2 below shows a comparison of the approved TO4 parameters to the proposed life and net salvage parameters used in calculating SDG&E's proposed TO5 Formula rates.

TABLE 2

Comparison of Life and Net Salvage Parameters
Depreciation Study as of December 31, 2017

		Approved TO4 Formula			Proposed		
Account	Description	ASL	Curve	FNS%	ASL	Curve	FNS%
E0135210	Struct & Imprv-Other	72	R2	-60.00%	74	R2.5	-75.00%
E0135220	Struct & Imprv-SWPL	72	R2	-60.00%	74	R2.5	-75.00%
E0135260	Struct & Imprv-SRPL	72	R2	0.00%	74	R2.5	-75.00%
E352	**Total**	**72**	**R2**		**74**	**R2.5**	**-75.00%**
E0135310	Station Equip.-Other	50	R1	-60.00%	50	R1.5	-75.00%
E0135320	Station Equip.-SWPL	50	R1	-60.00%	50	R1.5	-75.00%
E0135340	Station Equip.-Palomar	50	R1	-60.00%	50	R1.5	-75.00%
E0135360	Station Equip.-SRPL	50	R1	0.00%	50	R1.5	-75.00%
E353	**Total**	**50**	**R1**		**50**	**R1.5**	**-75.00%**
E0135410	Towers & Fxtrs-Other	70	R5	-100.00%	70	R5	-100.00%
E0135420	Towers & Fxtrs-SWPL	70	R5	-100.00%	70	R5	-100.00%
E0135460	Towers & Fxtrs-SRPL	70	R5	0.00%	70	R5	-100.00%
E354	**Total**	**70**	**R5**		**70**	**R5**	**-100.00%**
E0135510	Poles & Fxtrs-Other	45	R1.5	-100.00%	45	R1.5	-100.00%
E0135520	Poles & Fxtrs-SWPL	45	R1.5	-100.00%	45	R1.5	-100.00%
E0135560	Poles & Fxtrs-SRPL	45	R1.5	0.00%	45	R1.5	-100.00%
E355	**Total**	**45**	**R1.5**		**45**	**R1.5**	**-100.00%**
E0135610	Ovrhd Cnd & Dev-Other	58	S0	-100.00%	60	R2.5	-100.00%
E0135620	Ovrhd Cnd & Dev-SWPL	58	S0	-100.00%	60	R2.5	-100.00%
E0135660	Ovrhd Cnd & Dev-SRPL	58	S0	0.00%	60	R2.5	-100.00%
E356	**Total**	**58**	**S0**		**60**	**R2.5**	**-100.00%**
E0135700	Trans UG Conduit	60	R5	-45.00%	60	R5	-45.00%
E0135760	UG Conduit-SRPL	60	R5	0.00%	60	R5	-45.00%
E357	**Total**	**60**	**R5**		**60**	**R5**	**-45.00%**
E0135800	Trans UG Conductor	50	R3	-10.00%	50	R2	-10.00%
E0135860	UG Cond. & Dev-SRPL	50	R3	0.00%	50	R2	-10.00%
E358	**Total**	**50**	**R3**		**50**	**R2**	**-10.00%**
E0135910	Roads & Trails-Other	60	SQ	0.00%	60	SQ	0.00%
E0135920	Roads & Trails-SWPL	60	SQ	0.00%	60	SQ	0.00%
E0135960	Roads & Trails-SRPL	60	SQ	0.00%	60	SQ	0.00%
E359	**Total**	**60**	**SQ**		**60**	**SQ**	**0.00%**

V. DEPRECIATION RATES – TO5 FORMULA

Q. How do the current annual depreciation accrual expense and rates compare to the proposed annual accrual expense and rates for SDG&E's Transmission Accounts?

A. A comparison of the annual dollar impact of the current accrual rates to the proposed accrual rates is shown below in Table 3. The cumulative difference between accrual expense amounts is an increase of $19,563,958 between the current and proposed accrual expense based on December 31, 2017 balances.

Q. What is the driving factor to this increase in depreciation rates when comparing the approved TO4 Formula rates with the proposed TO5 Formula rates?

A. The inclusion of negative net salvage in the accounts, where applicable, related to Sunrise Power Link assets is the driving factor for the increase in depreciation expense. As mentioned earlier, the results of the settlement for TO4 rates used a zero percent net salvage factor for all Sunrise Power Link accounts. Outside of the Sunrise Power Link accounts, there are only two accounts, Accounts 352 and 353, where I proposed a change from the existing net salvage. Those two accounts moved from a negative 60 percent to a negative 75 percent net salvage. There were two accounts, Account 352 and Account 356, where the proposed life is an increase of two years over the existing, providing some offset to the effects Sunrise Power Link negative net salvage. Table 3 below provides a comparison by account of the change in annual depreciation expense.

TABLE 3

Comparison of Transmission Accounts
Depreciation Accrual Rates at December 31, 2017

		Plant	Current		Proposed		
		Balance	Rates	Expense	Rates	Expense	Difference
Account	Description	$	%	$	%	$	$
E0135210	Struct & Imprv-Other	$ 380,765,072	2.18%	$ 8,300,679	2.37%	$ 9,031,722	$ 731,044
E0135220	Struct & Imprv-SWPL	14,828,569	1.62%	240,223	2.18%	323,399	83,176
E0135260	Struct & Imprv-SRPL	121,020,368	1.39%	1,682,183	2.41%	2,918,746	1,236,562
E0135310	Station Equip.-Other	1,222,846,732	3.52%	43,044,205	3.61%	44,141,636	1,097,431
E0135320	Station Equip.-SWPL	272,105,465	4.02%	10,938,640	3.62%	9,841,219	(1,097,421)
E0135340	Station Equip.-Palomar	1,420,393	3.25%	46,163	3.76%	53,425	7,262
E0135360	Station Equip.-SRPL	161,967,663	2.01%	3,255,550	3.59%	5,820,517	2,564,967
E0135410	Towers & Fxtrs-Other	68,964,896	3.13%	2,158,601	2.87%	1,979,269	(179,332)
E0135420	Towers & Fxtrs-SWPL	62,015,338	2.65%	1,643,406	2.71%	1,678,922	35,516
E0135460	Towers & Fxtrs-SRPL	766,332,063	1.47%	11,265,081	2.96%	22,682,708	11,417,627
E0135510	Poles & Fxtrs-Other	526,506,752	4.65%	24,482,564	4.57%	24,074,930	(407,634)
E0135520	Poles & Fxtrs-SWPL	10,308,506	5.08%	523,672	3.40%	350,175	(173,498)
E0135560	Poles & Fxtrs-SRPL	3,343,704	2.26%	75,568	4.51%	150,735	75,168
E0135610	Ovrhd Cnd & Dev-Other	399,874,653	3.20%	12,795,989	3.28%	13,126,643	330,655
E0135620	Ovrhd Cnd & Dev-SWPL	46,248,992	1.77%	818,607	1.63%	754,619	(63,989)
E0135660	Ovrhd Cnd & Dev-SRPL	173,392,337	1.75%	3,034,366	3.45%	5,980,306	2,945,940
E0135700	Trans UG Conduit	280,352,906	2.43%	6,812,576	2.43%	6,805,948	(6,628)
E0135760	UG Conduit-SRPL	80,502,078	1.69%	1,360,485	2.47%	1,990,531	630,045
E0135800	Trans UG Conductor	264,166,329	2.08%	5,494,660	2.13%	5,627,323	132,664
E0135860	UG Cond. & Dev-SRPL	126,452,463	2.02%	2,554,340	2.19%	2,765,065	210,725
E0135910	Roads & Trails-Other	83,139,884	1.65%	1,371,808	1.69%	1,401,130	29,322
E0135920	Roads & Trails-SWPL	5,323,946	1.44%	76,665	1.51%	80,579	3,915
E0135960	Roads & Trails-SRPL	227,675,967	1.68%	3,824,956	1.66%	3,784,498	(40,458)
	Total	**$ 5,299,555,074**	**2.75%**	**$ 145,800,986**	**3.12%**	**$ 165,364,044**	**$ 19,563,058**
					Change in Expense		**13.42%**

VI. SUMMARY

Q. What is one of the greatest challenges in the depreciation rate calculation?

A. As stated in the NARUC's *Public Utility Depreciation Practices*, one of the greatest challenges is balancing the short-run and long-run interests affecting both the ratepayer and the Company. If the depreciation rates prescribed are too low, the revenue requirement in the short-run may be lower. However, these rates can be so low that revenue fails to recoup the capital invested by the end of the asset's life placing a burden on future ratepayers for assets that never served their interest. The situation can be reversed by placing more of the burden on current ratepayers, while future costs are minimal or non-existent.

Q. What objective should be taken into account to address this challenge?

A. The objective of computing depreciation is to allocate the cost or depreciation base over the property's service life by charging the appropriate portion of the consumption of plant taking place during each accounting period. The depreciation methods used in this study and recommended here achieve this objective for SDG&E and its customers.

Q. Do you have any summary remarks?

A. Yes. The Depreciation Study and analysis performed under my supervision was performed using standard depreciation processes and methodologies. The study followed standard depreciation rate calculation methods which have been repeatedly submitted and approved by the FERC. SDG&E should continue to periodically review the annual depreciation rates for its property so that appropriate rates are included in SDG&E revenue requirements to ensure intergenerational equity to its customers. In this way, SDG&E's depreciation expense will more accurately reflect its cost of operations and the rates for all customers will include an appropriate share of the capital expended for their benefit. The proposed depreciation rates contained in the Depreciation Study, SDG&E Exhibit No. SD-0016, are the result of a complete, comprehensive depreciation study. The depreciation rates are reasonable and appropriate given that they incorporate the service life and net salvage parameters currently anticipated for each of SDG&E's Transmission account investments over their average remaining lives and are based on the most current year end plant and reserve balances. The methods follow prior TO Formula filings, which have been reviewed and approved by the Commission and should be approved.

Q. Does this complete your testimony?

A. Yes.

VERIFICATION

Dane A. Watson hereby declares under penalty of perjury of the laws of the United States that the foregoing document is true and correct to the best of his knowledge and belief. See 28 U.S.C. § 1746.

Executed this 25th day of October, 2018

Dane A. Watson

EXHIBIT NO. SD-0015

TO THE PREPARED DIRECT TESTIMONY OF

DANE A. WATSON

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

LIST OF PRIOR TESTIMONY OF DANE A. WATSON

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos KY	2018	Gas Depreciation Rates
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A1710-007	San Diego Gas & Electric	2018	Electric Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Electric Depreciation Study
Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	SPS	2017	Electric Production Depreciation Study
Multistate	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
Multistate	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Public Utilities Board	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Natural Gas	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service of Colorado	2016	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	SPS NM	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
Hawaii	NA	NA	Hawaii American Water	2015	Water/Wastewater Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	SPS NM	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint-Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Xcel Energy	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
New Jersey	Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power-Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	SPS	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service of Colorado	2012	Gas and Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Minnesota Northern States Power	2012	Electric, Gas and Common Transmission, Distribution and General

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
Multistate	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service of Colorado	2009	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Public Utility Commission of Texas	35763	SPS	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	SPS	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service of Colorado	2006	Electric Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Texas, New Mexico	Public Utility Commission of Texas	32766	Xcel Energy	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9400	TXU Gas	2003-2004	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9313	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9225	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	24060	TXU	2001	Line Losses
Texas	Public Utility Commission of Texas	23640	TXU	2001	Line Losses
Texas	Railroad Commission of Texas	9145-9148	TXU Gas	2000-2001	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	22350	TXU	2000-2001	Electric Depreciation Study, Unbundling
Texas	Railroad Commission of Texas	8976	TXU Pipeline	1999	Pipeline Depreciation Study

Asset Location	Commission	Docket (If Applicable)	Company	Year	Description
Texas	Public Utility Commission of Texas	20285	TXU	1999	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	18490	TXU	1998	Transition to Competition
Texas	Public Utility Commission of Texas	16650	TXU	1997	Customer Complaint
Texas	Public Utility Commission of Texas	15195	TXU	1996	Mining Company Depreciation Study
Texas	Public Utility Commission of Texas	12160	TXU	1993	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study

EXHIBIT NO. SD-0016

TO THE PREPARED DIRECT TESTIMONY OF

DANE A. WATSON

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

SAN DIEGO GAS & ELECTRIC COMPANY

ELECTRIC TRANSMISSION UTILITY PLANT

DEPRECIATION RATE STUDY

AT DECEMBER 31, 2017

ALLIANCE CONSULTING GROUP

http://www.utilityalliance.com

SAN DIEGO GAS & ELECTRIC COMPANY
ELECTRIC TRANSMISSION UTILITY PLANT
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

San Diego Gas & Electric Company ("SDG&E" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's Electric Transmission utility plant depreciable assets as of December 31, 2017. This study is to be used in its Transmission Owner's ("TO") rate proceeding designated as SDG&E's TO5 Formula.

This study was conducted under a traditional depreciation study approach for life and net salvage. The straight line, broad group (average life), remaining life depreciation system was used. This methodology has been adopted by numerous state commissions and the Federal Energy Regulatory Commission ("FERC").

This study recommends an overall increase of $19.6 million in annual depreciation expense for transmission accounts compared to rates currently in effect. Appendix A shows the computation of the proposed depreciation rates. Appendix B demonstrates the change in depreciation expense for the various accounts. Appendix C compares the approved depreciation parameters to the proposed depreciation parameters. Appendix D shows the net salvage analysis.

SAN DIEGO GAS & ELECTRIC COMPANY

ELECTRIC TRANSMISSION UTILITY PLANT

DEPRECIATION RATE STUDY

AT DECEMBER 31, 2017

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PURPOSE

The purpose of this study is to develop depreciation rates for the TO5 depreciable property as recorded on SDG&E's books at December 31, 2017. The account-based depreciation rates were designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of SDG&E's property on a straight-line basis. Non-depreciable property is excluded from this study.

SDG&E provides electric transmission service in a service territory that includes San Diego and southern Orange counties. SDG&E has more than 1,984 miles of transmission lines and 162 substations that provide communities with access to local and regional energy sources. The transmission system connects power producers, or generators, with distribution companies who deliver power to where it is used in homes and businesses. SDG&E also has various other intangible and general plant assets utilized to serve its customers, but those are not included in this study.

STUDY RESULTS

Overall depreciation rates for all SDG&E depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual of $165.4 million based on SDG&E's depreciable investment at December 31, 2017. The annual equivalent depreciation expense calculated by the same method using the approved rates was $145.8 million.

Appendix A demonstrates the development of the annual depreciation rates and accruals. Appendix B presents a comparison of approved rates versus proposed rates by account. Appendix C presents a summary of mortality and net salvage estimates by account. Appendix D presents the net salvage analysis for all accounts. The change in depreciation expense is primarily due to the recognition of comparable net salvage for certain Sunrise Power Link accounts as found for other SDG&E transmission assets. A zero net salvage rate was included for the Sunrise Powerlink facilities in the approved (settled) TO4 Formula rates.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

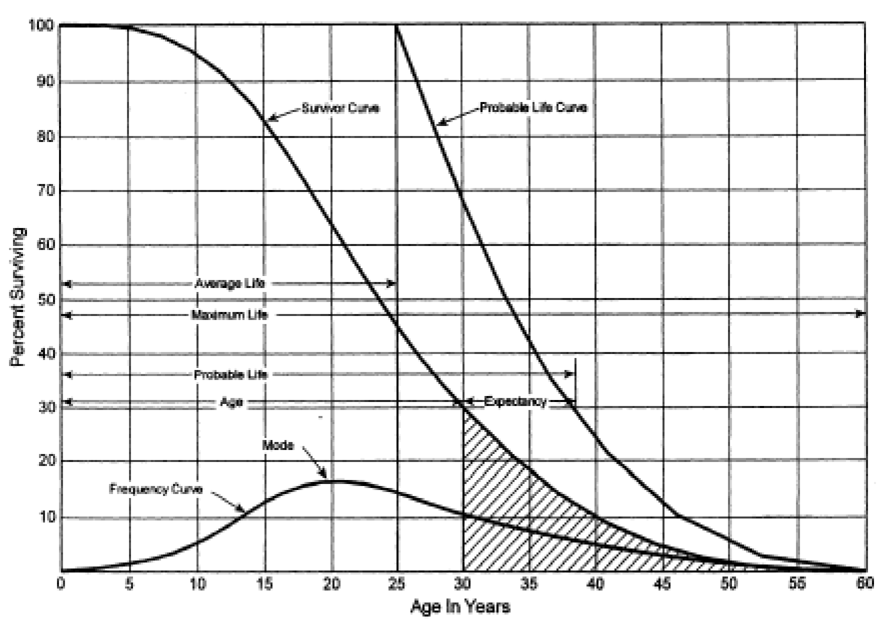
Basis of Depreciation Estimates

The straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual account level depreciation rates are shown in Appendix A.

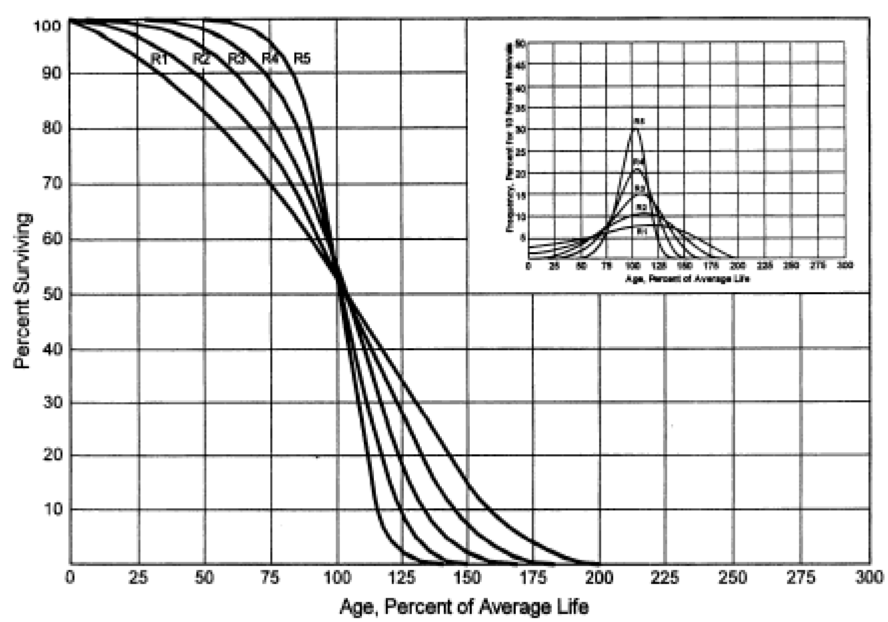
Actuarial analysis was used with each account within a function where sufficient data was available, and judgment was used to some degree on all accounts.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of "R" moded curves is shown below.



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. An "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. A special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least for example, any analysis requires choosing which bands to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for each account requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Average Life Group Depreciation

SDG&E's last transmission depreciation study for its TO4 Formula approved by FERC in Docket ER13-941-000 utilized the straight-line, average life group ("ALG"), remaining life methodology. At the request of SDG&E, this study continues to use the straight-line, average life group, remaining life depreciation system. After an average service life and dispersion were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ALG is defined by their respective account dispersion, life, and salvage estimates. A straight-line rate for each ALG is calculated by computing a composite remaining life for each group across all vintages within the group, dividing the remaining investment to be recovered by the remaining life to find the annual depreciation expense and dividing the annual depreciation expense by the surviving investment. The resultant rate for each ALG group is designed to recover all retirements less net salvage when the last unit retires. The ALG procedure recovers net book cost over the life of each account by averaging many components.

Theoretical Depreciation Reserve

The accumulated book depreciation reserve by account is maintained at an account level. The study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The average life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line remaining-life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(Average\ Remaining\ Life)}{(Average\ Service\ Life)} * (1 - Net\ Salvage\ Ratio)$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of depreciation rates and documenting the corresponding recommendations.

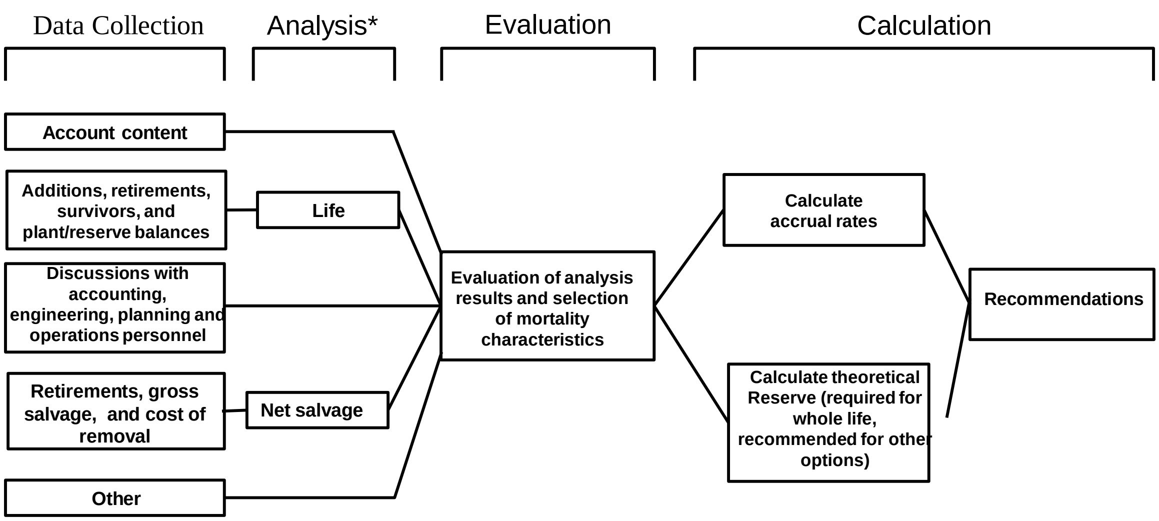
During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Further discussion on data review and adjustment is found in the Salvage Considerations Section of this study. Also as part of the Phase I data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion of this study in the life analysis and salvage analysis sections and also in workpapers.

Phase 2 is where the actuarial analysis is performed. Phase 2 and 3 overlap to a significant degree. The detailed property records information is used in phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. This information was then carried forward into phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and net salvage parameters. The historical analysis from phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[1] documents the steps used in conducting this study. Depreciation Systems[2], page 289 documents the same basic processes in performing a depreciation study which are: Statistical analysis, evaluation of statistical analysis, discussions with management, forecast assumptions, and document recommendations.

[1] INTRODUCTION TO DEPRECIATION FOR PUBLIC UTILITIES & OTHER INDUSTRIES, AGA EEI (2013).
[2] Depreciation Systems, F.K. Wolf & W.C. Fitch, Iowa State University Press, 1994.



Source: Introduction to Depreciation for Public Utilities and Other Industries, AGA EEI , 2013.

*Although not specifically noted, the mathematical analysis may need some level of input from other sources (for example, to determine analysis bands for life and adjustments to data used in all analysis).

Figure 1

SAN DIEGO GAS & ELECTRIC COMPANY

DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable accounts of SDG&E were calculated by the straight-line method, average life group procedure, and remaining-life technique. With this approach, remaining lives were calculated according to standard ALG expectancy techniques, using the Iowa Survivor Curves noted in the calculation. For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the average remaining life to yield the annual depreciation expense. These calculations are shown in Appendix A.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using the Retirement Rate actuarial methods. After establishment of appropriate average service lives and retirement dispersions, a remaining life was computed for each account. The composite remaining life for each account was determined by direct weighting (i.e. by multiplying vintage investment by the vintage remaining life and dividing by the plant balance for each account).

Account Calculation Process

Annual depreciation expense amounts for accounts other than production were calculated by the straight line, remaining life procedure.

In a whole life representation, the annual accrual rate is computed by the following equation,

$$\text{Annual Accrual Rate} = \frac{(100\% - \text{Net Salvage Percent})}{\text{Average Service Life}}$$

Use of the remaining life depreciation system adds a self-correcting mechanism, which accounts for any differences between theoretical and book depreciation reserve over the remaining life of the group. With the straight line, remaining life, average life group system using Iowa Curves, composite remaining lives were calculated according to standard broad group expectancy techniques, noted in the formula below:

$$\text{Composite Remaining Life} = \frac{\sum \text{Original Cost} - \text{Theoretical Reserve}}{\sum \text{Whole Life Annual Accrual}}$$

For each plant account, the difference between the surviving investment, adjusted for estimated net salvage, and the allocated book depreciation reserve, was divided by the composite remaining life to yield the annual depreciation expense as noted in this equation.

$$\text{Annual Depreciation Expense} = \frac{\text{Original Cost} - \text{Book Reserve} - (\text{Original Cost}) * (1 - \text{Net Salvage \%})}{\text{Composite Remaining Life}}$$

where the net salvage percent represents future net salvage.

Within a group, the sum of the group annual depreciation expense amounts, as a percentage of the depreciable original cost investment summed, gives the annual depreciation rate as shown below:

$$\text{Annual Depreciation Rate} = \frac{\sum \text{Annual Depreciation Expense}}{\sum \text{Original Cost}}$$

These calculations are shown in Appendix A.

LIFE ANALYSIS

The retirement rate actuarial analysis method was applied to all accounts for SDG&E. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Survivor Curves to obtain the most appropriate match. A selected curve for each account is shown in the Life Analysis Section of this report. The observed life tables for all analyzed placement and experience bands are provided in workpapers.

For each account using the overall band (i.e. placement from earliest vintage year which varied for each account through 2003), approved lives were used as a starting point. Then using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (i.e. L, S. or R) as an obviously better match than others. The next step would be to determine the most appropriate life using that dispersion pattern. For each account, an overall experience band and shorter bands were analyzed. Next placement bands of varying width were plotted with each experience band discussed above. For most accounts an overall placement band was analyzed along with shorter bands of approximately 20 and 50 years respectively. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa curve in top and mid range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

TRANSMISSION PLANT

Transmission Plant Accounts, FERC Accounts 351-359

In this study, all plant data within each subaccount of a major FERC account were combined by major FERC account for a single life analysis due to the similarity of the assets, their function, and operational characteristics. This analysis results in one life/dispersion pattern and net salvage recommendation by FERC account to be applied individually in the calculation of each respective TO5 subaccount depreciation accrual expense and rate. The previous TO4 depreciation study relied solely on the life and net salvage results of the primary subaccount ("Other") for each major FERC account to determine the life and net salvage for other subaccounts within each major FERC account. With more years of transactional data for the newer subaccounts, the combination of all subaccounts within a FERC account was a logical extension of the previous analysis. The following section gives an overall description of the major FERC account, discussion of the analysis and life recommendations as well as investment balances by subaccount at December 31, 2017. Last, we include a graph, if available, of the Company's combined account experience and proposed life and curve.

FERC Account 351 Battery Energy Storage Systems (BESS) (10 SQ)

This is a new account and currently does not have any investment. However, based on discussions with Company personnel, these types of assets are expected to be added in the future. Some of the ancillary equipment to be placed in this account could have a longer life than the batteries. However, based on a study from Sargent & Lundy, the overall life of the facility is expected to be limited by battery service life, which they state to be approximately 10 years. Items in this account can include:

1. Lithium or lead acid based batteries.
2. Steel enclosures.
3. Concrete pedestal foundations.
4. Electrical equipment.
5. Fencing.

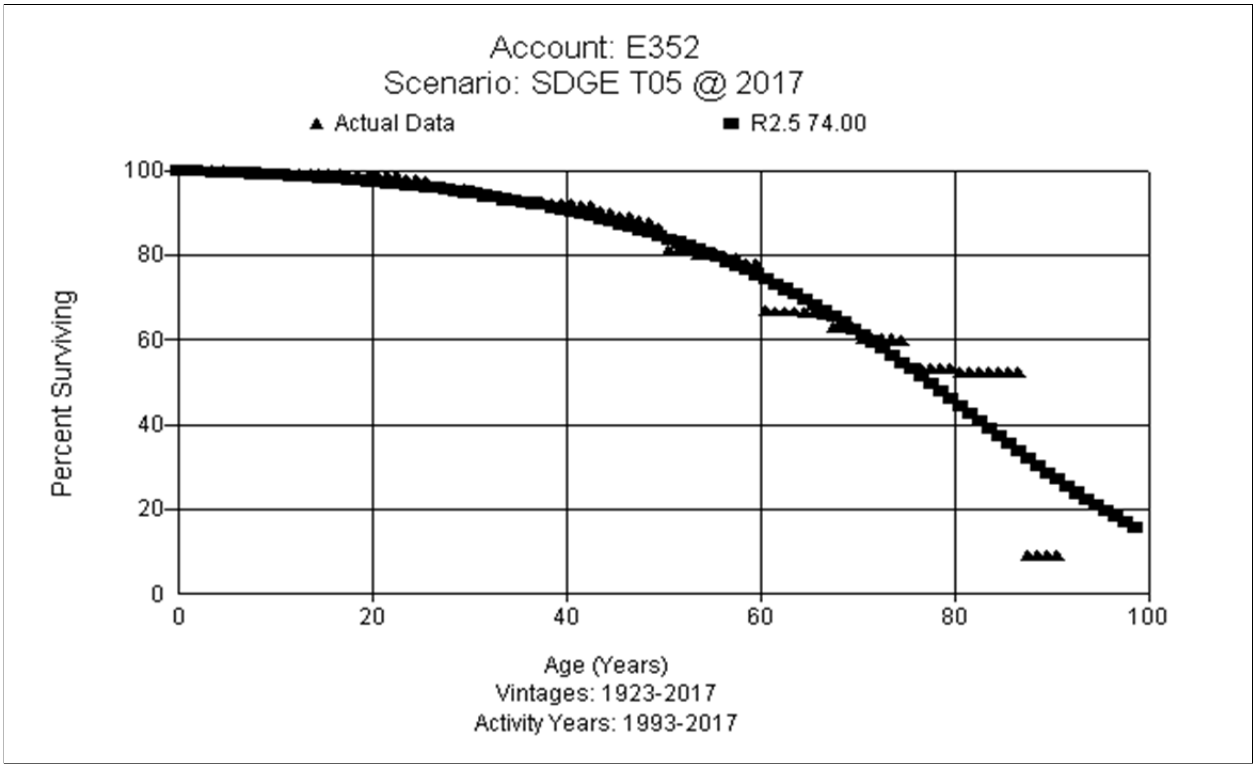
FERC Account 352 Structures & Improvements (74 R2.5)

This account consists of substation assets such as control buildings, fencing, landscaping/yard surfacing and station lighting. Items can include:

1. Buildings, roof, and HVAC.
2. Alarm, monitoring and security systems.
3. Lighting, walkways, and walls.
4. Landscaping, sprinklers, and irrigation.
5. Grading, roads, fences and gates.
6. Tanks, tower, vaults, and cable.
7. Foundations, concrete, and pad.
8. Platforms, railings, steps, gratings, etc.
9. Pumps.

The current life for this account is a 72 R2. While many assets in this account will have a long life, discussions with Company personnel indicated some assets such as fences will only last 20-30 years while longer-lived walls are seen in newer substations. Short-lived security infrastructure is recorded in this account in some cases but may also be recorded to Account 353. Paving (asphalt) will also only last 20-30 years. The philosophy for transmission aging infrastructure is to proactively replace before failure when possible.

The shorter-lived assets in the account are moderating the outward movement in the life of this account. The actuarial analysis included subaccounts 352.10 Other, 352.20 South West Powerlink (“SWPL”), and 352.60 Sunrise Powerlink (“SRPL”). This analysis indicated a slight increase in life along with a slightly steeper dispersion across the bands analyzed. Subaccount 352.10 has a current balance of $380.8 million and is related to substation structure assets other than those in Subaccounts 352.2 and 352.6. Subaccount 352.2 has a current balance of $14.8 million and is related to substation structure assets for SWPL. Subaccount 352.6 has a current balance of $121.0 million and is related to SRPL. Although a number of different bands were run, a full placement and experience band graph of the Company's combined 352 account experience and proposed curve is shown below.



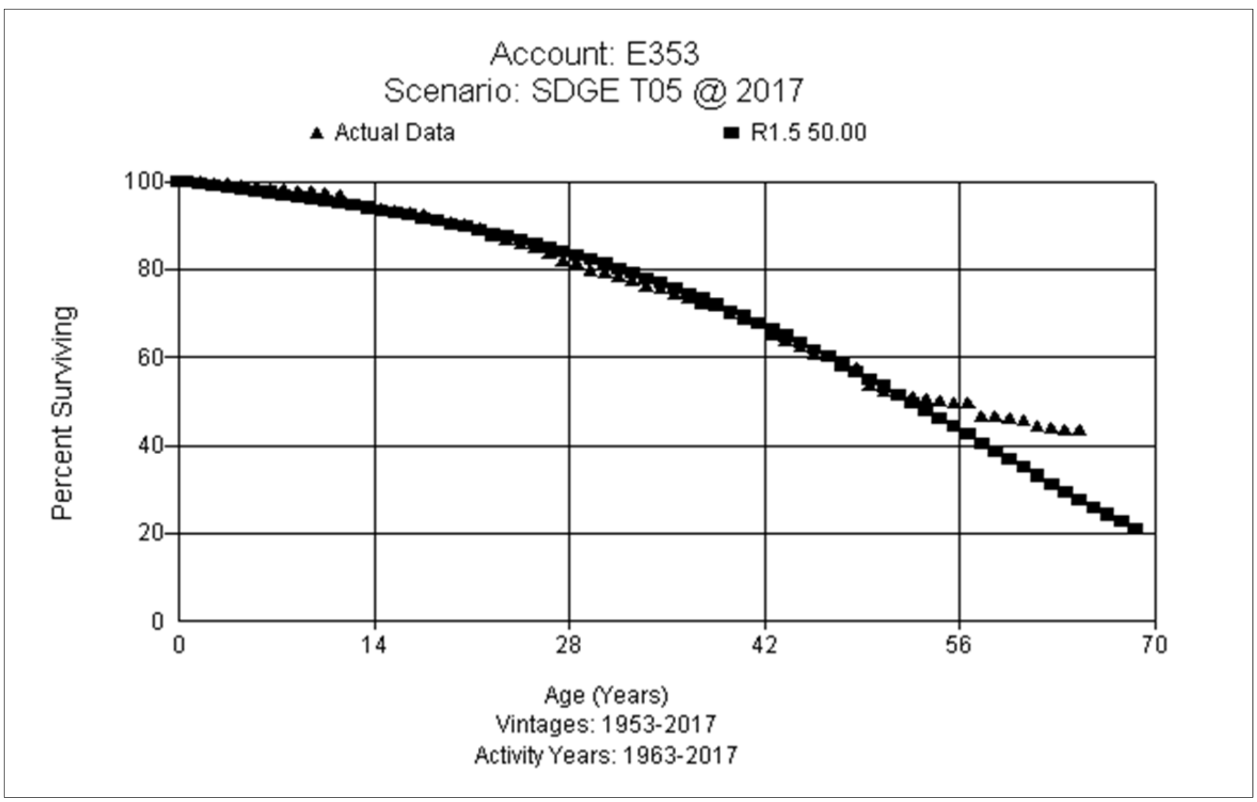
FERC Account 353 Substation Equipment (50 R1.5)

This account consists of the installed cost of 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. Items can include:

1. Bus compartments, concrete, brick, and sectional steel, including items permanently attached thereto.
2. Conduit, including concrete and iron duct runs not a part of a building.
3. Control equipment, including batteries battery charging equipment, transformers, remote relay boards, and connections.
4. Conversion equipment, including transformers, indoor and outdoor, frequency changers, motor generator sets, rectifiers, synchronous converters, motors, cooling equipment, and associated connections.
5. Fences.
6. Fixed and synchronous condensers, including transformers, switching equipment blowers, motors and connections.
7. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
8. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment, etc.
9. Platforms, railings, steps, gratings, etc. appurtenant to apparatus listed herein.
10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lightning arresters, cable and wire runs from and to outdoor connections or to manholes and the associated regulators, reactors, resistors, surge arresters, and accessory equipment.
11. Switchboards, including meters, relays, control wiring, etc.
12. Switching equipment, indoor and outdoor, including oil circuit breakers, operating mechanisms and truck and disconnect switches.
13. Tools and appliances.

The current life for all subaccounts for this FERC account is 50 R1. There is a mix of longer and shorter-lived assets within this account. Discussions with Company personnel indicated the various control and protection equipment have moved from analog to digital. New assets in this area are expected to live 10-15 years before needing to be changed out. The Company is working toward replacing the last generation of relays, which will probably be around 15 years old when retired. Communications into substations is being upgraded and will affect station batteries and maybe other RTU components in this account. Currently, the refresh cycle on batteries is around 10 years. The Company indicated more and more costs will be spent to protect critical assets. The new transformers have condition based monitoring installed and this monitoring equipment will have a shorter life. However, the goal is that the monitoring will help the transformers to last longer. The Company recently switched to polymer bushing on transformers which are not expected to last as long as the ceramic bushings. This may have a slightly shortening impact on the account in future years as more polymers are added to the account. The Company expects the life of transformers to be a little less than 60 years, with the newer transformers having a slightly shorter life. There is some underground cable in substations that are not expected to live longer than 30 years, especially for the terminations. Currently, over 90% of SDG&E’s circuit breakers are SF6 and they have already replaced the first generation of SF6 breakers. The SF6 circuit breakers are expected to have a life of 30 years at most. Capacitors/reactors are expected to last around 30 years. Relays have a life expectancy around 10-15 years. The necessary security equipment has a fairly short life, generally 5 years or less and the costs are growing. The foundations for equipment and steel would be expected to last for the life of the substation, but some will have to be replaced with the equipment to meet IEEE 693 seismic rules. Growth will generally create the need for the addition of substations not upgrading existing equipment. SDG&E has started installing some GIS substations, which are expected to have a shorter life when compared to a normal substation. With the change in the type of assets and mix in the account, the overall average service life is expected to decline as more short-lived assets are added to the account in future years. This study does not reflect that future expectation at this point.

The actuarial analysis included Accounts 353.10 Other, 353.20 SWPL, 353.40 Palomar, and 353.60 SRPL. The analysis indicates a majority of the fits to be around 50 years, which is the existing life. Depending on the bands analyzed, the fits generally were from 48 to 53 years. However, the majority of the analysis demonstrated around a 50 year life with an R dispersion. Giving considering to the information obtained from discussions with Company personnel and the indications in the life analysis, this study recommends retaining the existing life of 50 years, while moving to a slightly steeper R1.5 dispersion. The current balance in subaccount 353.10 – Station Equipment Other is $1.2 billion. The current balance for subaccount 353.20 Station Equipment - SWPL is $272.1 million. The current balance for subaccount 353.40 – Station Equipment – Palomar is $1.4 million. The current balance for subaccount 353.60 - Station Equipment – SRPL is $161.9 million. A graph of the Company's full band combined 353 accounts experience and proposed 50 R1.5 curve is shown below.



FERC Account 354 Transmission Towers & Fixtures (70 R5)

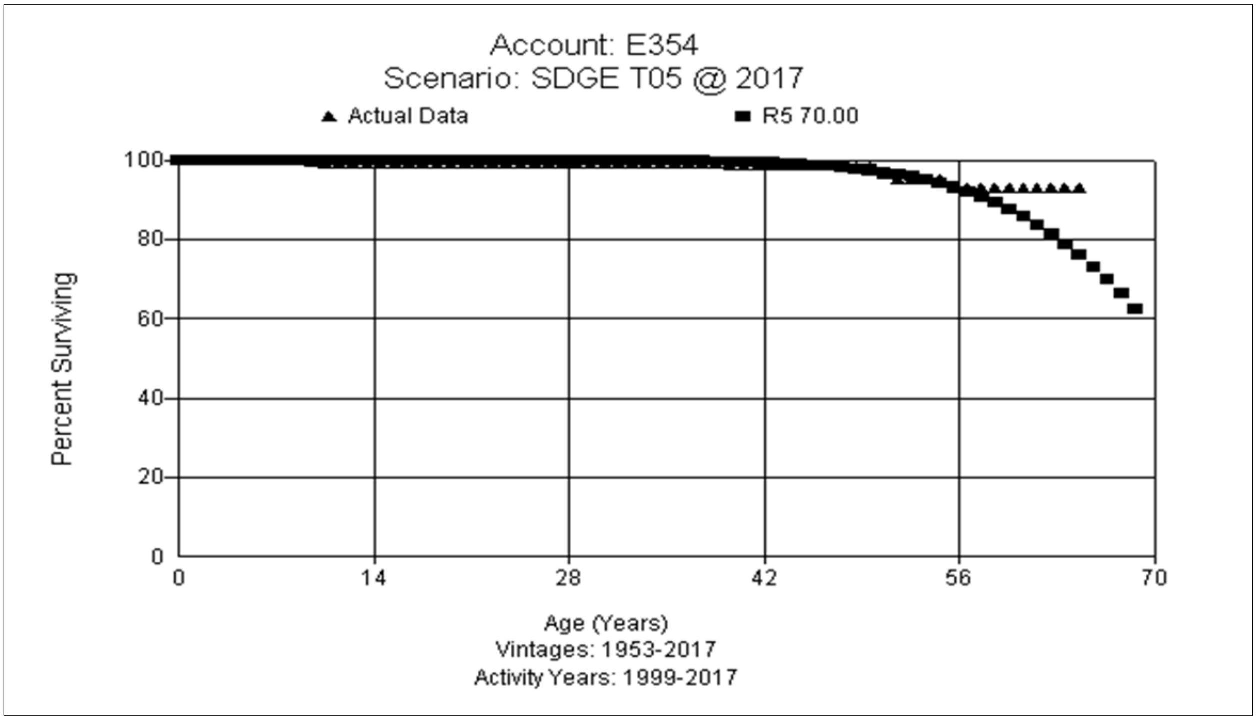
This account consists of the installed cost of towers and appurtenant fixtures used for supporting overhead transmission conductors including concrete foundations and lattice transmission structures. Items can include:

1. Anchors, guys, braces.
2. Brackets.
3. Cross arms, including braces.
4. Excavation, backfill, and disposal of excess excavated material.
5. Foundations.
6. Guards.
7. Insulator pins and suspension bolts.
8. Ladders and steps.
9. Railings, etc.
10. Towers.

The current life for all subaccounts for this FERC Account is 70 R5. Discussions with Company personnel indicated replacements can be driven by capacity increases as well as generation coming on line and normal failures. There are a few ISO approved upgrades that happen each year. There is also OH to UG line moves that occur. While the assets may have a shorter original design life of around 50 years, the longer existing life of 70 is still reasonable based on past experience.

The life analysis did not have enough historical retirement experience for a meaningful drop in the stub curve as shown in the graph below. The limited indications demonstrated that the existing 70 R5 remains a reasonable fit to the full placement and experience band. Giving consideration to Company information, operations, type of assets, and the analysis, this study recommends retention of the existing 70 R5. The current balance in subaccount 354.10 Transmission Towers & Fixtures – Other is $68.9 million. The current balance in subaccount 354.20 Transmission Towers & Fixtures – SWPL is $62.0 million. The current balance in subaccount 354.60 Transmission

Towers & Fixtures – SRPL is $766.3 million. A graph of the Company's experience and proposed 70 R5 curve is shown below.



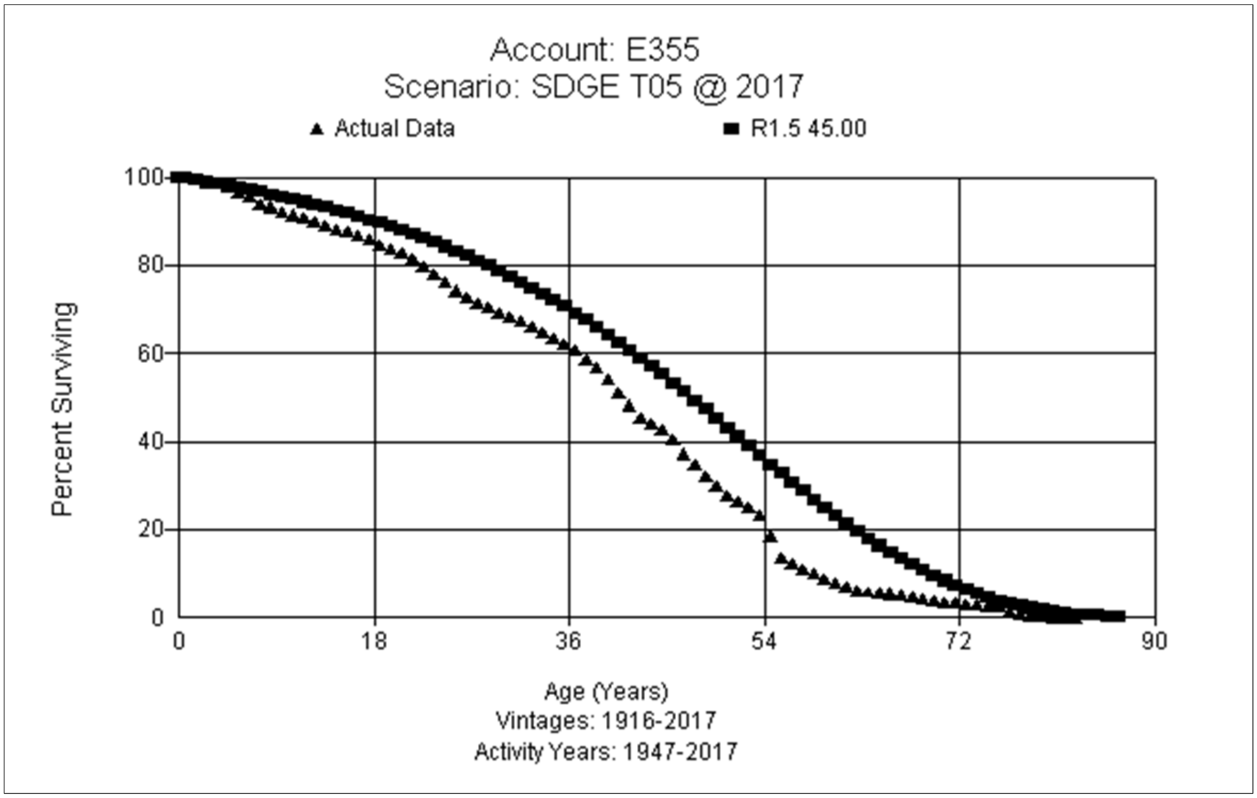
FERC Account 355 Transmission Poles & Fixtures (45 R1.5)

This account consists of installed cost of poles made of wood, steel, concrete, or other material, together with appurtenant fixtures used for supporting overhead transmission conductors. Items can include:

1. Anchors, head arm and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Cross arms and braces.
4. Excavation and backfill, including disposal of excess excavated material.
5. Extension arms.
6. Gaining, roofing stenciling, and tagging.
7. Insulator pins and suspension bolts.
8. Paving.
9. Pole steps.
10. Poles, wood, steel, concrete, or other material.
11. Racks complete with insulators.
12. Reinforcing and stubbing.
13. Settings.
14. Shaving and painting.

The current life of all subaccounts for this account is 45 R1.5. Discussions with Company personnel indicated there is a program to change out wood poles to steel poles in much of their territory due to fire threat zones. This change out is around 50% complete. We are seeing a shortening of the pole life based on the program with a lengthening life expected in future studies as more steel poles are added to the system. As of the study date there are approximately 8,125 wood poles, 4,126 steel poles, and 2,095 towers. Prior to the start of this program (pre-2010) there were very few steel poles on the system. There are 2,700 more poles to replace, which should be completed in 2020. Most of these poles are direct embedded (i.e. no foundations). The steel replacement poles directly embedded in the ground may have a reduced life expectancy when compared to steel poles on foundations. The system has very few concrete poles. Overall, without the early replacement, a 45 year life is a reasonable expectation for wood poles and up to 55 years for steel poles. Corrosion in highly irrigated areas and issues with galvanization are some causes of failure. Poles are also more likely to be relocated than towers.

The life analysis indicates a shorter life across the bands analyzed, which supports the Company's expectation that the replacement program would shorten the life of the account. The Company's expectation is it will eventually lengthen the life as a larger percentage of the poles moved from wood to steel. Looking at the full placement and experience band, the R1.5 dispersion with a shorter life would result in a good fit. However, considering the information from Company personnel, the current replacement program and its impact, the analysis and future expectations for this account, this study recommends retention of the existing 45 R1.5. The current balance in subaccount 355.10 – Transmission Poles & Fixtures – Other is $526.5 million. The current balance in subaccount 355.20 – Transmission Poles & Fixtures – SWPL is $10.3 million. The current balance in subaccount 355.60 – Transmission Poles & Fixtures – SRPL is $3.3 million. A graph of the Company's full band experience and proposed 45 R1.5 curve is shown below.


Account: E355
Scenario: SDGE T05 @ 2017
Actual Data
R1.5 45.00
100
80
60
40
20
0
Percent Surviving
0
18
36
54
72
90
Age (Years)
Vintages: 1916-2017
Activity Years: 1947-2017

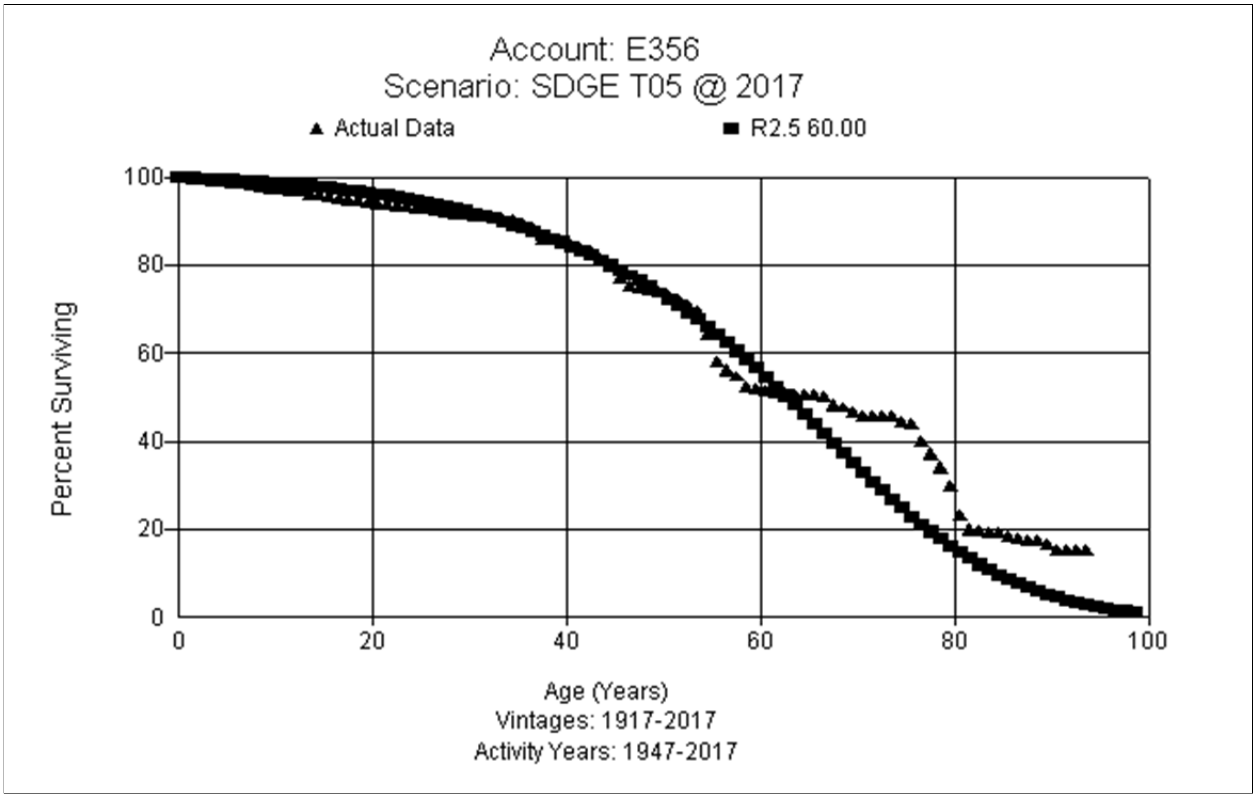
FERC Account 356 Overhead Conductors and Devices (60 R2.5)

This account consists of the installed cost of overhead conductors and devices used for transmission. Items can include:

1. Circuit breakers.
2. Conductors, including insulated and bare wires and cables.
3. Ground wires and ground clamps.
4. Insulators, including pin, suspension, and other types.
5. Lightning arresters.
6. Switches.
7. Other line devices.

The current life for all subaccounts is 58 S0. Discussions with Company personnel indicated the change out of wood to steel pole program may include the replacement of conductor. Undergrounding, wind fatigue, splice problems, capacity upgrades and relocations are also causes for replacement. The Company expects conductor should have a life at least as long as poles if not longer.

The life analysis indicated a small life increase as well as a change in dispersion pattern across the bands analyzed. Considering the discussions with Company personnel, replacement program impacts, the life analysis, and future expectations, this study recommends increasing the life to 60 years and changing to the R2.5 dispersion. The current balance for subaccount 356.10 Overhead Conductors and Devices – Other is $399.9 million. The current balance for subaccount 356.10 Overhead Conductors and Devices – SWPL is $46.2 million. The current balance for subaccount 356.10 Overhead Conductors and Devices – SRPL is $173.4 million. A graph of the Company's full band experience and proposed 60 R2.5 curve is shown below.


Account: E356
Scenario: SDGE T05 @ 2017
Actual Data
R2.5 60.00
Percent Surviving
100
80
60
40
20
0
0
20
40
60
80
100
Age (Years)
Vintages: 1917-2017
Activity Years: 1947-2017

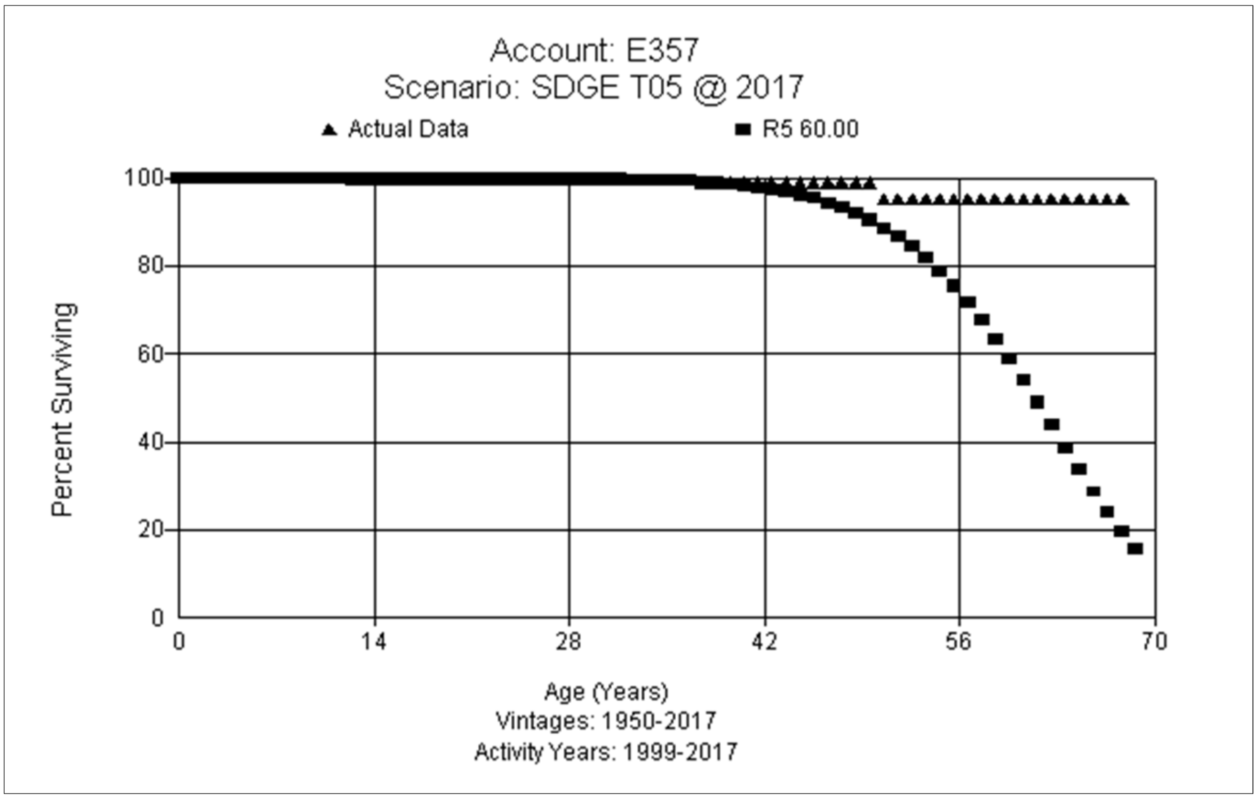
FERC Account 357 Underground Conduit (60 R5)

This account includes the cost installed of underground conduit, electric manholes, vaults, tunnels, and spreader head assembly used for housing transmission cables or wires. Items can include:

1. Conduit, concrete, brick or tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower.
2. Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material.
3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
4. Lighting systems.
5. Manholes, concrete or brick, including iron or steel, frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
6. Municipal inspection.
7. Pavement disturbed, including cutting and replacing pavement, pavement base and sidewalks.
8. Permits.
9. Protection of street openings.
10. Removal and relocation of subsurface obstructions.
11. Sewer connections, including drains, traps, tide valves, check valves, etc.
12. Sumps, including pumps.
13. Ventilating equipment.

The current life of all subaccounts is 60 R5. Discussions with Company personnel indicated underground conduit is normally laid with a spare conduit. Plastic conduit is encased in concrete consisting of 2 columns of 3 stacked conduits with 6” spacing with a communications conduit as well for each trench package. The Company expects conduit to last longer than the conductor. Assets in this account are not simply abandoned when retired. Vaults would be removed and potentially conduit filled.

The life analysis did not have enough historical retirement experience for a meaningful stub curve for any bands analyzed. Feedback with Company personnel continues to support the existing life. This study recommends retention of the existing 60 R5. The current balance for subaccount 357.00 Underground Conduit is $280.4 million. The current balance for subaccount 357.60 Underground Conduit - SRPL is $80.5 million. A graph of the Company's experience and proposed 60 R5 curve is shown below.



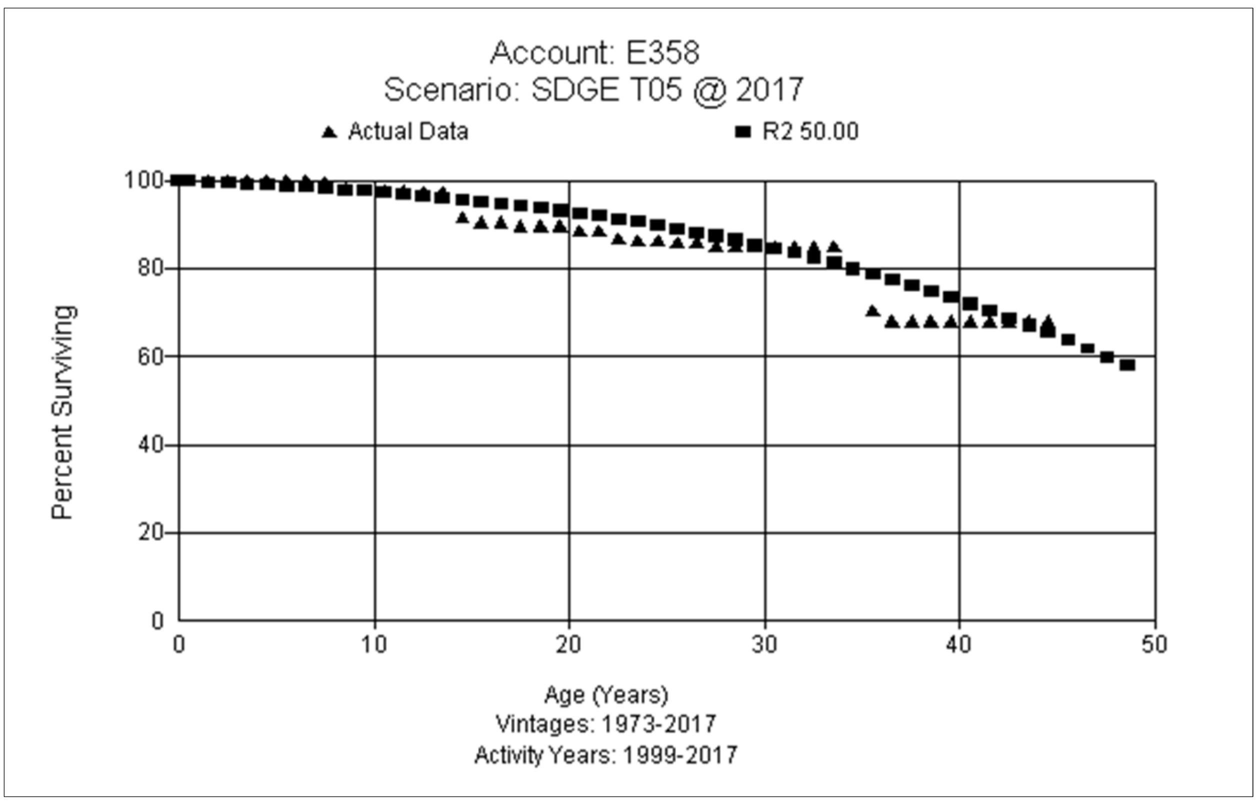
FERC Account 358 Underground Conductors & Devices (50 R2)

This account consists of the installed cost of underground conductors, line potheads, pipeline oil pumps, underground cable. and devices used for transmission purposes. Items can include:

1. Armored conductors, buried, including insulators, insulating materials, splices, potheads, trenching, etc.
2. Armored conductors, submarine, including insulators, insulating materials, splices in terminal chambers, potheads, etc.
3. Cables in standpipe, including pothead and connection from terminal chamber of manhole to insulators on pole.
4. Circuit breakers.
5. Fireproofing, in connection with any items listed herein.
6. Hollow-core oil-filled cable, including straight or stop joints pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, ventilating equipment, etc.
7. Lead and fabric covered conductors, including insulators, compound filled, oil filled, or vacuum splices, potheads, etc.
8. Lightning arresters.
9. Municipal inspection.
10. Permits.
11. Protection of street openings.
12. Racking of cables.
13. Switches.
14. Other line devices.

The current life of all subaccounts is 50 R3. The Discussions with Company personnel indicated there is approximately 154 miles of UG at the study date. There is about 20 miles that is direct buried and targeted for replacement. This program will start right away and be completed in 2022. They have been doing some direct buried replacement every year and some acceleration in the last year or so. Most of the underground conductor is XLPE material. Using the history of distribution, they expect a life around 40 years stating the existing 50 year life seems too long for this type of material.

The combined full band analysis indicates a longer life than Company expectations. The mid-placement band fits the existing, 50 years. In more recent bands, the percent surviving does not drop to 90%, but the R3 50 is still a good fit. After reviewing various analysis bands, the account's asset characteristics, and information from Company personnel, this study recommends retention of the 50 year life but moving to the R2 dispersion based on the mid-placement band fit. The current balance for subaccount 358.0 Underground Conductors & Devices is $264.2 million. The current balance for subaccount 358.0 Underground Conductors & Devices - SRPL is $126.4 million. A graph of the Company's experience and proposed 50 R2 curve is shown below.



FERC Account 359 Roads and Trails (60 SQ)

This account includes the installed cost of roads, trails, and bridges. used primarily as transmission facilities. Items can include:

1. Bridges, including foundation piers, girders, trusses, flooring, etc.
2. Clearing land.
3. Roads, including grading, surfacing, culverts, etc.
4. Structures constructed and maintained in connection with other items included in this account.
5. Trails, including grading, surfacing, culverts, etc.

The current life for all subaccounts is 60 R4. There is insufficient history to analyze this account with actuarial analysis. The life was set at 60 SQ in the TO3 settlement and has been retained, as it is in this study. No analysis or fits were performed. The current balance for subaccount 359.10 Roads and Trails - Other is $83.1 million. The current balance for subaccount 359.20 Roads and Trails - SWPL is $5.3 million. The current balance for subaccount 359.1 Roads and Trails - SRPL is $227.7 million. No graph is shown.

SALVAGE ANALYSIS

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset).

Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Some plant assets can experience significant negative removal cost percentages due to the timing of the original addition versus the retirement. For example, a transmission asset in FERC Account 355 with a current installed cost of $500 (2017) would have had an installed cost of $64.73[3] in 1972 (which is the proposed average life of the account). A removal cost of $50 for the asset calculated (incorrectly) on current installed cost would only have a negative 10 percent removal cost ($50/$500). However, a correct removal cost calculation would show a negative 77 percent removal cost for that asset ($50/$64.73). Inflation from the time of installation of the asset until the time of its removal must be taken into account in the calculation of the removal cost percentage because the depreciation rate, which includes the removal cost percentage, will be applied to the original installed cost of assets. The net salvage analysis uses the history of the individual accounts to estimate the future net salvage that SDG&E can expect in its operations. As a result, the analysis not only looks at the historical experience of SDG&E, but also takes into account recent and expected changes in operations that could reasonably lead to different future expectations for net salvage than were experienced in the past.

Salvage Characteristics

For each account, data for retirements, gross salvage, and cost of removal were derived from 1991-2017.

3 Using the Handy-Whitman Bulletin No. 187, E-6, line 36, $64.73 = $500 x 87/672.

Moving averages, which remove timing differences between retirement and salvage and removal cost, were analyzed over periods varying from one to 10 years. The analysis of net salvage is shown in Appendix D.

TRANSMISSION PLANT

Transmission Plant Accounts, FERC Accounts 351-359

In this study, all plant data by TO5 subaccounts were combined for a single net salvage analysis into the major FERC account. This is reasonable due to the similarity of the assets and the processes followed at the time of retirement and replacement. This is also consistent with the life analysis and prior studies. This analysis results in the application of one net salvage factor to be applied individually in the calculation of each TO5 subaccount depreciation accrual expense and rate. This study gives an overall description of the major FERC account and then describes certain details that support the net salvage proposal.

FERC Account 351 Battery Energy Storage Systems (BESS) (-15%)

This is a new account and currently does not have any investment. However, based on discussions with Company personnel, these types of assets are expected to be added in the future. It is expected at retirement that the BESS sites will incur cost of removal that will exceed any gross salvage. Sargent & Lundy conducted a Decommission Study for the Company's future BESS sites. However, based on the independent study, estimated installed cost of the BESS sites, discussions with Company personnel and judgment, a negative 15 net salvage for this account is estimated and recommended.

FERC Account 352 Structures & Improvements (-75%)

This account consists of control building, fencing, landscaping/yard surfacing and station lighting. Similar to the life analysis, a combined net salvage analysis was performed. The net salvage analysis included subaccounts 352.10 Other, 352.20

SWPL, and 352.60 SRPL. The existing net salvage percent for subaccounts 352.10 Other and 352.20 SWPL is negative 60 percent and 352.60 SRPL (per settlement) is 0 percent net salvage. Discussions with Company personnel indicated the assets and retirement processes are similar for all three accounts making the combined analysis reasonable and consistent with past studies. Discussions with Company personnel indicated the normal flow of capital expenditures (capex) is to record cost of removal at the very beginning of a job, then normal construction capex until completion; then once the project is completed, the retirements are processed. With larger transmission projects, the necessary information to unitize or process retirements can come in for months, up to 3 years, before unitizing and processing is complete. This is not unique to SDG&E but common to the industry and is the reason for the utilizing moving averages in the analysis.

The combined 352 (352.10 Other, 352.20 SWPL, and 352.60 SRPL) net salvage historic experience shows five and ten year moving averages to be negative 180 and negative 207 percent respectively. The existing negative 60 percent is well below the indications across the bands. To move incrementally toward expectations of the future and recognition of the timing differences in the recording of removal cost and retirements, this study conservatively recommends a negative 75 percent net salvage factor for this account supported by the combined net salvage analysis.

FERC Account 353 Substation Equipment (-75%)

This account consists of transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity. Similar to the life analysis, a combined net salvage analysis was performed. The net salvage analysis included subaccounts 353.10 Other, 353.20 SWPL, 353.40 Palomar, and 353.60 SRPL. The existing net salvage percent for subaccounts 353.10 Other, 353.20 SWPL, and 353.40 Palomar is negative 60 percent and 353.60 SRPL (per settlement) is 0 percent net salvage. Discussions with Company personnel indicated the assets and retirement processes are similar for all four accounts making the combined analysis reasonable and is also consistent with past studies.

In this study the combined analysis of Accounts 353.10 Other, 353.20 SWPL, 353.40 Palomar, and 353.60 SRPL net salvage historic experience shows five and ten year moving averages to be negative 75 and negative 106 percent, respectively. There was one significant retirement in 2016 related to removing a 500kV capacitor from Imperial Valley Substation; this is related to the big synchronous condenser projects being installed at that site and others. This study recommends moving incrementally toward expectations of the future, this study recommends a negative 75 percent net salvage rate supported by the combined analysis for all 353 subaccounts in the study.

FERC Account 354 Transmission Towers & Fixtures (-100%)

This account consists of towers and appurtenant fixtures used for supporting overhead transmission conductors including concrete foundations and lattice transmission structures. Similar to the life analysis and the TO4 Formula, a combined net salvage analysis was performed. The net salvage analysis included subaccounts 354.10 Other, 354.20 SWPL, and 354.60 SRPL. The existing net salvage percent for subaccounts 354.10 Other and 354.20 SWPL is negative 100 percent. The existing net salvage for subaccount 354.60 SRPL (per settlement) is 0 percent net salvage. Discussions with Company personnel indicated the assets and retirement processes are similar for all three accounts making the combined analysis reasonable and consistent with past studies.

In the combined analysis of Accounts 354.10 Other, 354.20 SWPL and 354.60 SRPL net salvage historic experience shows five and ten year moving averages for net salvage in this account to be 0 (due to no retirements from 2012-2017) and negative 758 percent, respectively. Discussions with Company personnel indicated similar to the other accounts, work orders tracking retirements, salvage and removal remain open collecting charges over numerous months and/years. Company personnel indicated the current process is creating more negative net salvage by the mismatch. The Company has installed new software and continues to evaluate the process to refine how retirements and associated cost of removal are recorded. Based upon the analysis indications and the information provided by Company personnel, this study recommends retention of the existing negative 100 percent net salvage and applying to all subaccounts at this time.

FERC Account 355 Transmission Poles & Fixtures (-100%)

This account consists of installed cost of poles made of wood, steel, concrete, or other material, together with appurtenant fixtures used for supporting overhead transmission conductors. Similar to the life analysis and the TO4 Formula, a combined net salvage analysis was performed. The net salvage analysis included subaccounts 355.10 Other, 355.20 SWPL, and 355.60 SRPL. The existing net salvage percent for subaccounts 355.10 Other and 355.20 SWPL is negative 100 percent. The existing net salvage for subaccount 355.60 SRPL (per settlement) is 0 percent net salvage. Discussions with Company personnel indicated the assets and retirement processes are similar for all three accounts making the combined analysis reasonable and consistent with past studies.

Discussions with Company personnel indicated there are several replacement programs to change out wood poles to steel poles in much of their territory due to fire threat zones. There has been a large increase to cost of removal charged on capital jobs due to the replacement programs and the work orders are often open for many months so it is not unusual to see removal cost recorded years ahead of retirements. The combined 355 net salvage historic experience shows five and ten year moving averages for net salvage in this account to be negative 109 and negative 128 percent respectively. The analysis suggests cost of removal is increasing making the net salvage more negative when compared to the existing. There is some impact from the various replacement programs and the timing differences that occur. Based upon information provided by Company personnel regarding timing differences and the analysis, this study recommends not making any changes to the existing net salvage at this time. The existing net salvage rate of negative 100 percent is retained and is proposed to be applied to all 355 subaccounts.

FERC Account 356 Overhead Conductors and Devices (-100%)

This account consists of overhead conductors and devices used for transmission. Similar to the life analysis and the TO4 Formula, a combined net salvage analysis was performed. The net salvage analysis included subaccounts 356.10 Other, 356.20 SWPL, and 356.60 SRPL. The existing net salvage percent for subaccounts 356.10 Other and 356.20 SWPL is negative 100 percent. The existing net salvage for subaccount 356.60 SRPL (per settlement) is 0 percent net salvage. Discussions with Company personnel indicated the assets and retirement processes are similar for all three accounts making the combined analysis reasonable and consistent with past studies.

Discussions with Company personnel indicated there are several replacement programs. There has been a large increase to cost of removal charged on capital jobs due to the replacement programs and the work orders are often open for many months so it is not unusual to see removal cost being recorded years ahead of retirements.

The combined 356 net salvage historic experience shows five and ten year moving averages for net salvage in this account to be negative 453 and negative 312 percent, respectively. The analysis suggests cost of removal is increasing making the net salvage more negative when compared to the existing. There is some impact from the various replacement programs. However, due to the replacement programs and the timing differences in recording net salvage and retirements, this study recommends not making any changes at this time, so the existing net salvage rate of negative 100 percent is retained and is proposed to be applied to all 356 subaccounts.

FERC Account 357.00 Underground Conduit (-45%)

This account includes underground conduit, electric manholes, vaults, tunnels, and spreader head assembly used for housing transmission cables or wires. The net salvage included subaccounts 357.00 and 357.60 SRPL. The existing net salvage percent for account 357.00 (except 357.60) is negative 45 percent. The existing net salvage for subaccount 357.60 SRPL is 0 percent net salvage per settlement. Discussions with Company personnel indicated the assets and retirement processes are similar making the combined analysis reasonable and consistent with past studies.

Discussions with Company personnel indicated underground conduit is normally laid with a spare conduit. Plastic conduit is encased in concrete consisting of 2 columns of 3 stacked conduits with 6" spacing with a communications conduit as well for each trench package. Similar to Accounts 355 and 356, work orders can remain open for a long time and there are timing differences in the recording of net salvage costs and the retirements.

In the most recent years of the analysis, there were no retirements recorded but removal cost had been recorded over time. This was noted by Company personnel. Based on the timing differences and the analysis, the most recent activity does not provide a good indication of current trends. This study recommends making no changes at this time and retains the existing negative 45 percent and proposes it to be applied to all 357 subaccounts.

FERC Account 358 Underground Conductors and Devices (-10%)

This account consists of underground conductor, line potheads, pipeline oil pumps, and underground cable. The net salvage included accounts 358.00 and 358.60 SRPL. The existing net salvage percent for account 358.00 (excluding 358.60) is negative 10 percent. The existing net salvage for subaccount 358.60 SRPL is 0 percent net salvage per settlement.

There has been a large increase in cost of removal. Discussions with Company personnel indicated there are some timing differences in recording cost of removal and retirements. The combined 358 net salvage historic experience shows five and ten year moving averages for net salvage in this account to be negative 172 and negative 104 percent respectively. The analysis suggests cost of removal is increasing making the net salvage more negative when compared to the existing. There is some impact from the various replacement programs. Due to the replacement programs and the timing differences in recording net salvage and retirements, this study recommends not making any changes at this time. The existing net salvage rate of negative 10 percent is retained and proposed to be applied to all 358 subaccounts.

FERC Account 359 Roads and Trails (0%)

This account consists of bridges, trails, and roads. Similar to the life analysis and the TO4 Formula, a combined net salvage analysis was performed. The net salvage analysis included subaccounts 359.10 Other, 359.20 SWPL, and 359.60 SRPL. The existing net salvage percent for subaccounts 359.10 Other, 359.20 SWPL and 359.60 SRPL is 0 percent.

The combined analysis indicates some cost of removal had been recorded. Discussions with Company personnel indicated this was a result of moving to a new system and the rules for allocation. Based on the characteristics of the assets in this account and past history, this study recommends retention of a 0 percent net salvage and is proposed to be applied to all 359 subaccounts.

APPENDIX A - Computation of Depreciation Accrual Rate

San Diego Gas and Electric
T05
Computation of Transmission Account Depreciation Accrual Rates
Depreciation Study as of December 31, 2017

Account	Description	Plant Balance	Book Depreciation	Net Salvage	Net Salvage Amount	Unaccrued Balance	Remaining Life	Annual Accrual	Annual Accrual Rate	Life Reserve	COR Reserve	Life Accrual Rate	COR Accrual Rate
		$	$	%	$	$		$	%	$	$	%	%
E0135210	Struct & Imprv-Other	$ 380,765,072	$ 53,281,035	-75.00%	$ (285,573,804)	$ 613,057,840	67.88	$ 9,031,722	2.37%	$ 39,045,728	$ 14,235,307	1.32%	1.05%
E0135220	Struct & Imprv-SWPL	14,828,569	8,278,463	-75.00%	(11,121,426)	17,671,532	54.64	323,399	2.18%	7,062,590	1,215,873	0.96%	1.22%
E0135260	Struct & Imprv-SRPL	121,020,368	10,874,757	-75.00%	(90,765,276)	200,910,887	68.83	2,918,746	2.41%	9,696,267	1,178,490	1.34%	1.08%
E0135310	Station Equip.-Other	1,222,846,732	219,422,686	-75.00%	(917,135,049)	1,920,559,094	43.51	44,141,636	3.61%	177,036,172	42,386,515	1.97%	1.64%
E0135320	Station Equip.-SWPL	272,105,465	77,149,104	-75.00%	(204,079,099)	399,035,459	40.55	9,841,219	3.62%	62,520,651	14,628,453	1.90%	1.72%
E0135340	Station Equip.-Palomar	1,420,393	346,240	-75.00%	(1,065,295)	2,139,447	40.05	53,425	3.76%	254,089	92,152	2.05%	1.71%
E0135360	Station Equip.-SRPL	161,967,663	17,926,930	-75.00%	(121,475,748)	265,516,481	45.62	5,820,517	3.59%	17,249,175	677,755	1.96%	1.63%
E0135410	Towers & Fixtrs-Other	68,964,896	41,068,156	-100.00%	(68,964,896)	96,861,635	48.94	1,979,269	2.87%	23,512,746	17,555,410	1.35%	1.52%
E0135420	Towers & Fixtrs-SWPL	62,015,338	62,694,700	-100.00%	(62,015,338)	61,335,977	36.53	1,678,922	2.71%	35,346,319	27,348,381	1.18%	1.53%
E0135460	Towers & Fixtrs-SRPL	766,332,063	69,601,153	-100.00%	(766,332,063)	1,463,062,974	64.50	22,682,708	2.96%	62,560,234	7,040,919	1.42%	1.54%
E0135510	Poles & Fixtrs-Other	526,506,752	94,819,604	-100.00%	(526,506,752)	958,193,901	39.80	24,074,930	4.57%	51,634,396	43,185,208	2.27%	2.31%
E0135520	Poles & Fixtrs-SWPL	10,308,506	11,685,223	-100.00%	(10,308,506)	8,931,789	25.51	350,175	3.40%	6,369,364	5,315,859	1.50%	1.90%
E0135560	Poles & Fixtrs-SRPL	3,343,704	584,885	-100.00%	(3,343,704)	6,102,523	40.48	150,735	4.51%	357,711	227,175	2.21%	2.30%
E0135610	Ovrhd Cnd & Dev-Other	399,874,653	147,475,381	-100.00%	(399,874,653)	652,273,924	49.69	13,126,643	3.28%	79,898,165	67,577,217	1.61%	1.67%
E0135620	Ovrhd Cnd & Dev-SWPL	46,248,992	67,359,121	-100.00%	(46,248,992)	25,138,864	33.31	754,619	1.63%	34,506,673	32,852,448	0.76%	0.87%
E0135660	Ovrhd Cnd & Dev-SRPL	173,392,337	18,789,394	-100.00%	(173,392,337)	327,995,279	54.85	5,980,306	3.45%	17,170,813	1,618,581	1.64%	1.81%
E0135700	Trans UG Conduit	280,352,906	52,935,246	-45.00%	(126,158,807)	353,576,467	51.95	6,805,948	2.43%	36,785,200	16,150,046	1.67%	0.76%
E0135760	UG Conduit-SRPL	80,502,078	8,234,993	-45.00%	(36,225,935)	108,493,020	54.50	1,990,531	2.47%	6,878,847	1,356,146	1.68%	0.79%
E0135800	Trans UG Conductor	264,166,329	45,621,217	-10.00%	(26,416,633)	244,961,745	43.53	5,627,323	2.13%	43,138,831	2,482,386	1.92%	0.21%
E0135860	UG Cond. & Dev-SRPL	126,452,463	14,396,203	-10.00%	(12,645,246)	124,701,507	45.10	2,765,065	2.19%	13,918,212	477,991	1.97%	0.21%
E0135910	Roads & Trails-Other	83,139,884	9,114,581	0.00%	-	74,025,303	52.83	1,401,130	1.69%	9,783,524	(668,943)	1.67%	0.02%
E0135920	Roads & Trails-SWPL	5,323,946	2,781,264	0.00%	-	2,542,681	31.55	80,579	1.51%	2,781,264	-	1.51%	0.00%
E0135960	Roads & Trails-SRPL	227,675,967	21,417,182	0.00%	-	206,258,784	54.50	3,784,498	1.66%	21,417,182	-	1.66%	0.00%
	Total	**$ 5,299,555,074**	**$ 1,055,857,520**		**$ (3,889,649,558)**	**$ 8,133,347,112**		**$ 165,364,044**	**3.12%**	**$ 758,924,153**	**$ 296,933,367**		
E0135100	Battery Energy Storage Systems			-15.00%			10.00		11.50%				

APPENDIX B - Comparison of Depreciation Accrual

San Diego Gas and Electric
T05
Comparison of Transmission Account
Depreciation Accrual Rates at December 31, 2017

Account	Description	Plant Balance $	Current Depreciation Rates %	Current Depreciation $	Proposed Depreciation Rates %	Proposed Depreciation $	Difference $
E0135210	Struct & Imprv-Other	$ 380,765,071.96	2.18%	$ 8,300,678.57	2.37%	$ 9,031,722.33	$ 731,043.77
E0135220	Struct & Imprv-SWPL	14,828,568.54	1.62%	240,222.81	2.18%	323,398.76	83,175.95
E0135260	Struct & Imprv-SRPL	121,020,367.94	1.39%	1,682,183.11	2.41%	2,918,745.52	1,236,562.40
E0135310	Station Equip.-Other	1,222,846,731.63	3.52%	43,044,204.95	3.61%	44,141,635.53	1,097,430.58
E0135320	Station Equip.-SWPL	272,105,464.69	4.02%	10,938,639.68	3.62%	9,841,219.02	(1,097,420.66)
E0135340	Station Equip.-Palomar	1,420,392.88	3.25%	46,162.77	3.76%	53,424.67	7,261.91
E0135360	Station Equip.-SRPL	161,967,663.36	2.01%	3,255,550.03	3.59%	5,820,516.72	2,564,966.69
E0135410	Towers & Fixtrs-Other	68,964,895.53	3.13%	2,158,601.23	2.87%	1,979,268.84	(179,332.39)
E0135420	Towers & Fixtrs-SWPL	62,015,338.29	2.65%	1,643,406.46	2.71%	1,678,921.99	35,515.53
E0135460	Towers & Fixtrs-SRPL	766,332,063.43	1.47%	11,265,081.33	2.96%	22,682,708.42	11,417,627.09
E0135510	Poles & Fixtrs-Other	526,506,752.15	4.65%	24,482,563.97	4.57%	24,074,930.05	(407,633.92)
E0135520	Poles & Fixtrs-SWPL	10,308,505.68	5.08%	523,672.09	3.40%	350,174.54	(173,497.55)
E0135560	Poles & Fixtrs-SRPL	3,343,703.96	2.26%	75,567.71	4.51%	150,735.44	75,167.73
E0135610	Ovrhd Cnd & Dev-Other	399,874,652.51	3.20%	12,795,988.88	3.28%	13,126,643.40	330,654.52
E0135620	Ovrhd Cnd & Dev-SWPL	46,248,992.36	1.77%	818,607.16	1.63%	754,618.57	(63,988.60)
E0135660	Ovrhd Cnd & Dev-SRPL	173,392,336.67	1.75%	3,034,365.89	3.45%	5,980,305.80	2,945,939.91
E0135700	Trans UG Conduit	280,352,905.52	2.43%	6,812,575.60	2.43%	6,805,947.80	(6,627.80)
E0135760	UG Conduit-SRPL	80,502,077.88	1.69%	1,360,485.12	2.47%	1,990,530.51	630,045.39
E0135800	Trans UG Conductor	264,166,329.37	2.08%	5,494,659.65	2.13%	5,627,323.44	132,663.79
E0135860	UG Cond. & Dev-SRPL	126,452,463.41	2.02%	2,554,339.76	2.19%	2,765,065.04	210,725.28
E0135910	Roads & Trails-Other	83,139,884.02	1.65%	1,371,808.09	1.69%	1,401,129.95	29,321.86
E0135920	Roads & Trails-SWPL	5,323,945.56	1.44%	76,664.82	1.51%	80,579.38	3,914.56
E0135960	Roads & Trails-SRPL	227,675,966.54	1.68%	3,824,956.24	1.66%	3,784,497.99	(40,458.25)
	Total	$ 5,299,555,073.88	2.75%	$ 145,800,985.94	3.12%	$ 165,364,043.70	$ 19,563,057.76
						Change	13.42%
E0135100	Battery Energy Storage Systems				11.50%		

APPENDIX C – Comparison of Mortality Characteristics

Comparison of Mortality Characteristics
As of 12-31-2017

					Proposed		
4010 Electric Transmission		**ASL TO4**	**Iowa Curve**	**FNS% TO4**	**Life**	**Curve**	**Net Salv**
E0135210	Struct & Imprv-Other	72	R2	-60.00%			-75.00%
E0135220	Struct & Imprv-SWPL	72	R2	-60.00%			-75.00%
E0135260	Struct & Imprv-SRPL	72	R2	0.00%			-75.00%
E352	Total	72			74	R2.5	-75.00%
E0135310	Station Equip.-Other	50	R1	-60.00%			-75.00%
E0135320	Station Equip.-SWPL	50	R1	-60.00%			-75.00%
E0135340	Station Equip.-Palomar	50	R1	-60.00%			-75.00%
E0135360	Station Equip.-SRPL	50	R1	0.00%			-75.00%
E353	Total	50			50	R1.5	-75.00%
E0135410	Towers & Fixtrs-Other	70	R5	-100.00%			-100.00%
E0135420	Towers & Fixtrs-SWPL	70	R5	-100.00%			-100.00%
E0135460	Towers & Fixtrs-SRPL	70	R5	0.00%			-100.00%
E354	Total	70			70	R5	-100.00%
E0135510	Poles & Fixtrs-Other	45	R1.5	-100.00%			-100.00%
E0135520	Poles & Fixtrs-SWPL	45	R1.5	-100.00%			-100.00%
E0135560	Poles & Fixtrs-SRPL	45	R1.5	0.00%			-100.00%
E355	Total	45			45	R1.5	-100.00%
E0135610	Ovrhd Cnd & Dev-Other	58	S0	-100.00%			-100.00%
E0135620	Ovrhd Cnd & Dev-SWPL	58	S0	-100.00%			-100.00%
E0135660	Ovrhd Cnd & Dev-SRPL	58	S0	0.00%			-100.00%
E356	Total	58			60	R2.5	-100.00%
E0135700	Trans UG Conduit	60	R5	-45.00%			-45.00%
E0135760	UG Conduit-SRPL	60	R5	0.00%			-45.00%
E357	Total	60			60	R5	-45.00%
E0135800	Trans UG Conductor	50	R3	-10.00%			-10.00%
E0135860	UG Cond. & Dev-SRPL	50	R3	0.00%			-10.00%
E358	Total	50			50	R2	-10.00%
E0135910	Roads & Trails-Other	60	SQ	0.00%			0.00%
E0135920	Roads & Trails-SWPL	60	SQ	0.00%			0.00%
E0135960	Roads & Trails-SRPL	60	SQ	0.00%			0.00%
E359	Total	60			60	SQ	0.00%
TO4 Detail	Total Elec Trans (May 2012) w/ Sunrise at July 2012						
E0135100	Battery Storage Energy Systems				10		-15.00%

APPENDIX D - Net Salvage Analysis

SAN DIEGO GAS AND ELECTRIC T05
RETIREMENT AND NET SALVAGE
AS ADJUSTED
DATA THROUGH DECEMBER 2017

Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
352.1	1991	63,296.00	0.00	12,554.00	(12,554.00)	-19.83%										
352.1	1992	62,850.00	0.00	20,025.00	(20,025.00)	-31.86%	-25.83%									
352.1	1993	56,865.00	12,676.00	17,417.00	(4,741.00)	-8.34%	-20.69%	-20.39%								
352.1	1994	41,189.00	0.00	20,194.00	(20,194.00)	-49.03%	-25.43%	-27.94%	-25.65%							
352.1	1995	4,692.00	0.00	88.00	(88.00)	-1.88%	-44.21%	-24.35%	-27.20%	-25.17%						
352.1	1996	10,091.00	0.00	22,840.60	(22,840.60)	-226.35%	-155.10%	-77.04%	-42.42%	-38.64%	-33.66%					
352.1	1997	6,570.00	0.00	4,424.00	(4,424.00)	-67.34%	-163.64%	-128.10%	-76.02%	-43.79%	-39.68%	-34.56%				
352.1	1998	7,510.07	0.00	6,470.48	(6,470.48)	-86.16%	-77.38%	-139.57%	-117.18%	-77.11%	-46.30%	-41.52%	-36.09%			
352.1	1999	3,419.40	0.00	3,223.98	(3,223.98)	-94.28%	-88.70%	-80.68%	-133.96%	-114.76%	-77.91%	-47.56%	-42.45%	-36.87%		
352.1	2000	152,000.00	130,150.72	6,424.56	123,726.16	81.40%	77.53%	69.99%	67.28%	48.31%	47.04%	29.49%	21.87%	12.09%	7.14%	
352.1	2001	0.00	0.00	147,335.00	(147,335.00)	NA	-15.53%	-17.26%	-16.47%	-22.26%	-33.73%	-32.91%	-35.86%	-30.32%	-30.60%	
352.1	2002	8,462.91	0.00	5,921.92	(5,921.92)	-69.97%	-1810.92%	-18.40%	-18.02%	-22.89%	-24.53%	-35.36%	-34.54%	-37.09%	-31.47%	
352.1	2003	0.00	0.00	0.00	0.00	NA	-69.97%	-1810.92%	-95.51%	-19.99%	-22.89%	-24.53%	-35.36%	-34.54%	-37.09%	
352.1	2004	3,174.57	0.00	3,447.71	(3,447.71)	-108.60%	-108.60%	-80.51%	-80.51%	-20.15%	-21.67%	-24.45%	-26.00%	-36.57%	-35.74%	
352.1	2005	154,838.12	0.00	53,204.37	(53,204.37)	-34.36%	-35.85%	-35.85%	-34.03%	-126.09%	-27.06%	-27.78%	-29.11%	-29.85%	-35.58%	
352.1	2006	36,680.00	0.00	19,335.00	(19,335.00)	-52.71%	-37.88%	-39.03%	-39.03%	-40.32%	-112.84%	-29.71%	-30.33%	-31.47%	-32.10%	
352.1	2007	161,429.00	0.00	29,617.00	(29,617.00)	-18.35%	-24.71%	-28.94%	-28.69%	-29.65%	-30.59%	-71.00%	-26.16%	-26.61%	-27.46%	
352.1	2008	148,523.00	0.00	426,255.00	(426,255.00)	-287.00%	-147.08%	-137.09%	-94.76%	-105.39%	-105.39%	-104.81%	-133.52%	-84.41%	-84.46%	
352.1	2009	146,263.00	0.00	708,540.00	(708,540.00)	-484.43%	-384.96%	-255.23%	-236.24%	-190.97%	-190.56%	-190.56%	-189.02%	-211.36%	-156.52%	
352.1	2010	62,912.89	0.00	99,693.94	(99,693.94)	-158.46%	-386.39%	-345.12%	-237.80%	-230.91%	-188.09%	-187.74%	-187.74%	-186.36%	-206.75%	
352.1	2011	87,533.87	0.00	302,694.70	(302,694.70)	-345.80%	-267.46%	-374.42%	-249.52%	-258.27%	-246.55%	-205.38%	-205.00%	-205.00%	-203.59%	
352.1	2012	26,414.57	0.00	55,646.59	(55,646.59)	-210.67%	-314.48%	-258.98%	-141.75%	-337.72%	-256.28%	-245.13%	-205.55%	-205.18%	-205.18%	
352.1	2013	67,687.06	0.00	65,199.87	(65,199.87)	-96.33%	-128.42%	-233.18%	-173.19%	-315.18%	-307.42%	-240.83%	-231.47%	-197.27%	-196.95%	
352.1	2014	442,463.34	0.00	379,297.55	(379,297.55)	-85.72%	-87.13%	-93.21%	-80.14%	-131.37%	-193.34%	-207.51%	-180.80%	-176.82%	-160.29%	
352.1	2015	172,948.72	0.00	362,238.20	(362,238.20)	-209.45%	-120.49%	-118.10%	-113.70%	-146.17%	-147.07%	-196.11%	-207.80%	-184.56%	-180.99%	
352.1	2016	399,610.32	0.00	735,293.18	(735,293.18)	-184.00%	-191.69%	-145.50%	-136.40%	-144.05%	-158.81%	-158.79%	-192.67%	-201.68%	-184.43%	
352.1	2017	110,783.70	0.00	986,123.67	(986,123.67)	-890.13%	-337.27%	-304.92%	-185.08%	-211.83%	-211.80%	-220.77%	-217.91%	-243.62%	-247.49%	-209.11%
352.2	1991	0.00	0.00	0.00	0.00	NA										
352.2	1992	0.00	0.00	0.00	0.00	NA	NA									
352.2	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
352.2	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
352.2	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
352.2	1996	4,200.00	0.00	741.90	(741.90)	-17.66%	-17.66%	-17.66%	-17.66%	-17.66%	-17.66%					
352.2	1997	0.00	0.00	0.00	0.00	NA	-17.66%	-17.66%	-17.66%	-17.66%	-17.66%	-17.66%				
352.2	1998	2,200.00	0.00	0.00	0.00	0.00%	0.00%	-11.59%	-11.59%	-11.59%	-11.59%	-11.59%	-11.59%			
352.2	1999	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	-11.59%	-11.59%	-11.59%	-11.59%	-11.59%	-11.59%		
352.2	2000	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	-11.59%	-11.59%	-11.59%	-11.59%	-11.59%	-11.59%	
352.2	2001	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	-11.59%	-11.59%	-11.59%	-11.59%	-11.59%	
352.2	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	-11.59%	-11.59%	-11.59%	-11.59%	
352.2	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	-11.59%	-11.59%	-11.59%	
352.2	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	0.00%	0.00%	-11.59%	-11.59%	
352.2	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	-11.59%	
352.2	2006	25,992.00	0.00	3,540.00	(3,540.00)	-13.62%	-13.62%	-13.62%	-13.62%	-13.62%	-13.62%	-13.62%	-13.62%	-12.56%	-12.56%	
352.2	2007	206,767.00	0.00	0.00	0.00	0.00%	-1.52%	-1.52%	-1.52%	-1.52%	-1.52%	-1.52%	-1.52%	-1.52%	-1.51%	
352.2	2008	0.00	0.00	74,493.00	(74,493.00)	NA	-36.03%	-33.53%	-33.53%	-33.53%	-33.53%	-33.53%	-33.53%	-33.53%	-33.53%	
352.2	2009	7,379.00	0.00	8,450.00	(8,450.00)	-114.51%	-1124.04%	-38.73%	-34.54%	-36.01%	-36.01%	-36.01%	-36.01%	-36.01%	-36.01%	
352.2	2010	232,687.22	0.00	182,642.09	(182,642.09)	-78.49%	-79.60%	-110.63%	-59.44%	-56.92%	-56.92%	-56.92%	-56.92%	-56.92%	-56.92%	
352.2	2011	0.00	0.00	28,223.54	(28,223.54)	NA	-90.62%	-91.36%	-91.36%	-65.75%	-62.89%	-62.89%	-62.89%	-62.89%	-62.89%	
352.2	2012	0.00	0.00	0.00	0.00	NA	NA	-90.62%	-87.84%	-122.39%	-65.75%	-62.89%	-62.89%	-62.89%	-62.89%	
352.2	2013	0.00	0.00	0.00	0.00	NA	NA	NA	-12.13%	-91.36%	-122.39%	-65.75%	-62.89%	-62.89%	-62.89%	
352.2	2014	0.00	0.00	26.63	(26.63)	NA	NA	NA	NA	-90.63%	-91.37%	-122.40%	-65.76%	-62.89%	-62.89%	
352.2	2015	176,870.64	0.00	212.51	(212.51)	-0.12%	-0.14%	-0.14%	-0.14%	-16.09%	-51.54%	-52.66%	-70.53%	-47.15%	-45.80%	
352.2	2016	0.00	0.00	19,163.12	(19,163.12)	NA	-10.95%	-10.97%	-10.97%	-10.97%	-26.93%	-56.22%	-57.26%	-75.12%	-50.22%	
352.2	2017	0.00	0.00	102,430.32	(102,430.32)	NA	NA	-68.87%	-68.87%	-68.88%	-68.88%	-84.84%	-81.23%	-81.82%	-99.69%	
352.6	1991	0.00	0.00	0.00	0.00	NA										
352.6	1992	0.00	0.00	0.00	0.00	NA	NA									
352.6	1993	0.00	0.00	0.00	0.00	NA	NA	NA								

SAN DIEGO GAS AND ELECTRIC T05
RETIREMENT AND NET SALVAGE
AS ADJUSTED
DATA THROUGH DECEMBER 2017

Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
352.6	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
352.6	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
352.6	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
352.6	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
352.6	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
352.6	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
352.6	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
352.6	2013	100,445.73	0.00	20,565.34	(20,565.34)	-20.47%	-20.47%	-20.47%	-20.47%	-20.47%	-20.47%	-20.47%	-20.47%	-20.47%	-20.47%	
352.6	2014	36,863.51	0.00	25,791.67	(25,791.67)	-69.97%	-33.76%	-33.76%	-33.76%	-33.76%	-33.76%	-33.76%	-33.76%	-33.76%	-33.76%	
352.6	2015	0.00	0.00	5,134.28	(5,134.28)	NA	-83.89%	-37.50%	-37.50%	-37.50%	-37.50%	-37.50%	-37.50%	-37.50%	-37.50%	
352.6	2016	0.00	0.00	12,958.58	(12,958.58)	NA	NA	-119.05%	-31.96%	-46.94%	-46.94%	-46.94%	-46.94%	-46.94%	-46.94%	
352.6	2017	0.00	0.00	109.41	(109.41)	NA	NA	NA	-49.38%	-47.02%	-47.02%	-47.02%	-47.02%	-47.02%	-47.02%	
E352 Total	1991	63,296.00	0.00	12,554.00	(12,554.00)	-19.83%										
E352 Total	1992	62,850.00	0.00	20,025.00	(20,025.00)	-31.86%	-25.83%									
E352 Total	1993	56,865.00	12,676.00	17,417.00	(4,741.00)	-8.34%	-20.69%	-20.39%								
E352 Total	1994	41,189.00	0.00	20,194.00	(20,194.00)	-49.03%	-25.43%	-27.94%	-25.65%							
E352 Total	1995	4,692.00	0.00	88.00	(88.00)	-1.88%	-44.21%	-24.35%	-27.20%	-25.17%						
E352 Total	1996	14,291.00	0.00	23,582.50	(23,582.50)	-165.02%	-124.69%	-72.90%	-41.53%	-38.15%	-33.38%					
E352 Total	1997	6,570.00	0.00	4,424.00	(4,424.00)	-67.34%	-134.25%	-109.95%	-72.35%	-42.90%	-39.18%	-34.28%				
E352 Total	1998	9,710.07	0.00	6,470.48	(6,470.48)	-66.64%	-66.92%	-112.78%	-98.02%	-71.63%	-44.63%	-40.54%	-35.49%			
E352 Total	1999	3,419.40	0.00	3,223.98	(3,223.98)	-94.28%	-73.84%	-71.67%	-110.92%	-97.69%	-72.60%	-45.87%	-41.46%	-36.25%		
E352 Total	2000	152,000.00	130,150.72	6,424.56	123,726.16	81.40%	77.53%	69.06%	66.41%	46.25%	45.07%	28.35%	21.13%	11.65%	6.85%	
E352 Total	2001	0.00	0.00	147,335.00	(147,335.00)	NA	-15.53%	-17.26%	-16.25%	-21.97%	-32.96%	-32.20%	-35.19%	-29.90%	-30.25%	
E352 Total	2002	8,462.91	0.00	5,921.92	(5,921.92)	-69.97%	-1810.92%	-18.40%	-18.02%	-22.60%	-24.23%	-34.57%	-33.80%	-36.41%	-31.04%	
E352 Total	2003	0.00	0.00	0.00	0.00	NA	-69.97%	-1810.92%	-95.51%	-19.99%	-22.60%	-24.23%	-34.57%	-33.80%	-36.41%	
E352 Total	2004	3,174.57	0.00	3,447.71	(3,447.71)	-108.60%	-108.60%	-80.51%	-80.51%	-20.15%	-21.67%	-24.14%	-25.69%	-35.76%	-34.98%	
E352 Total	2005	154,838.12	0.00	53,204.37	(53,204.37)	-34.36%	-35.85%	-35.85%	-34.03%	-126.09%	-27.06%	-27.78%	-28.91%	-29.66%	-35.15%	
E352 Total	2006	62,672.00	0.00	22,875.00	(22,875.00)	-36.50%	-34.98%	-36.04%	-36.04%	-37.29%	-101.59%	-28.61%	-29.20%	-30.12%	-30.73%	
E352 Total	2007	368,196.00	0.00	29,617.00	(29,617.00)	-8.04%	-12.18%	-18.05%	-17.95%	-18.53%	-19.26%	-43.93%	-18.51%	-18.85%	-19.46%	
E352 Total	2008	148,523.00	0.00	500,748.00	(500,748.00)	-337.15%	-102.64%	-95.49%	-75.35%	-82.71%	-82.71%	-82.56%	-102.32%	-71.22%	-71.30%	
E352 Total	2009	153,642.00	0.00	716,990.00	(716,990.00)	-466.66%	-403.00%	-186.07%	-170.16%	-149.06%	-148.91%	-148.91%	-148.17%	-164.55%	-129.00%	
E352 Total	2010	295,600.11	0.00	282,336.03	(282,336.03)	-95.51%	-222.45%	-250.95%	-155.29%	-150.93%	-135.68%	-135.61%	-135.61%	-135.15%	-147.47%	
E352 Total	2011	87,533.87	0.00	330,918.24	(330,918.24)	-378.05%	-160.06%	-247.82%	-194.11%	-176.61%	-168.75%	-152.37%	-152.27%	-152.27%	-151.72%	
E352 Total	2012	26,414.57	0.00	55,646.59	(55,646.59)	-210.67%	-339.25%	-163.33%	-118.77%	-265.08%	-177.45%	-169.71%	-153.56%	-153.45%	-153.45%	
E352 Total	2013	168,132.79	0.00	85,765.21	(85,765.21)	-51.01%	-72.69%	-167.44%	-81.76%	-201.23%	-224.18%	-160.41%	-154.49%	-141.80%	-141.72%	
E352 Total	2014	479,326.85	0.00	405,115.85	(405,115.85)	-84.52%	-75.82%	-81.10%	-71.78%	-109.72%	-155.02%	-174.92%	-139.35%	-135.75%	-127.68%	
E352 Total	2015	349,819.36	0.00	367,584.99	(367,584.99)	-105.08%	-93.19%	-86.08%	-83.86%	-112.04%	-108.57%	-143.83%	-160.63%	-133.58%	-130.74%	
E352 Total	2016	399,610.32	0.00	767,414.88	(767,414.88)	-192.04%	-151.45%	-125.34%	-110.25%	-118.14%	-133.20%	-127.03%	-153.66%	-166.58%	-143.01%	
E352 Total	2017	110,783.70	0.00	1,088,663.40	(1,088,663.40)	-982.69%	-363.66%	-258.50%	-166.00%	-180.05%	-180.58%	-191.24%	-176.48%	-198.01%	-207.32%	-167.73%
353.1	1991	1,867,476.00	41,903.00	373,394.00	(331,491.00)	-17.75%										
353.1	1992	271,058.00	99,669.00	71,325.00	28,344.00	10.46%	-14.18%									
353.1	1993	797,673.00	88,966.00	178,438.00	(89,472.00)	-11.22%	-5.72%	-13.37%								
353.1	1994	439,382.00	76,179.00	34,179.00	42,000.00	9.56%	-3.84%	-1.27%	-10.39%							
353.1	1995	760,552.25	193,776.00	77,299.00	116,477.00	15.31%	13.21%	3.45%	4.29%	-5.66%						
353.1	1996	138,398.00	0.00	65,582.00	(65,582.00)	-47.39%	5.66%	6.94%	0.16%	1.32%	-7.01%					

SAN DIEGO GAS AND ELECTRIC T05
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Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
353.1	1997	173,944.91	98,955.57	126,161.19	(27,205.62)	-15.64%	-29.71%	2.21%	4.34%	-1.03%	0.18%	-7.35%				
353.1	1998	270,816.98	0.00	47,872.53	(47,872.53)	-17.68%	-16.88%	-24.12%	-1.80%	1.00%	-2.78%	-1.52%	-7.94%			
353.1	1999	74,152.87	0.00	198,810.69	(198,810.69)	-268.11%	-71.51%	-52.78%	-51.65%	-15.73%	-9.75%	-10.19%	-8.27%	-11.97%		
353.1	2000	0.00	0.00	826,383.90	(826,383.90)	NA	-1382.54%	-311.06%	-206.79%	-177.37%	-74.01%	-54.24%	-41.31%	-36.52%	-29.21%	
353.1	2001	68,916.94	0.00	133,480.43	(133,480.43)	-193.68%	-1392.78%	-809.87%	-279.95%	-209.88%	-178.92%	-79.56%	-59.23%	-45.17%	-40.13%	
353.1	2002	1,112,720.06	40,047.56	1,500,599.19	(1,460,551.63)	-131.26%	-134.90%	-204.84%	-192.74%	-174.71%	-158.44%	-150.08%	-101.69%	-85.60%	-70.14%	
353.1	2003	1,268,550.57	20,005.08	594,818.21	(574,813.13)	-45.31%	-85.47%	-88.52%	-88.52%	-126.53%	-115.98%	-110.10%	-107.31%	-83.20%	-73.74%	
353.1	2004	2,033,081.89	750.00	729,092.65	(728,342.65)	-35.82%	-39.47%	-62.61%	-61.64%	-83.05%	-86.07%	-82.23%	-79.91%	-79.04%	-66.88%	
353.1	2005	2,983,691.31	0.00	1,521,386.49	(1,521,386.49)	-50.99%	-44.84%	-44.94%	-38.18%	-59.18%	-70.24%	-72.19%	-70.30%	-69.11%	-68.74%	
353.1	2006	4,729,864.00	0.00	1,781,925.00	(1,781,925.00)	-37.67%	-42.82%	-41.36%	-36.60%	-50.03%	-50.84%	-57.61%	-58.88%	-57.99%	-57.42%	
353.1	2007	4,202,297.00	0.00	777,923.00	(777,923.00)	-18.51%	-28.66%	-34.25%	-29.26%	-35.38%	-41.92%	-42.55%	-47.59%	-48.59%	-48.09%	
353.1	2008	987,672.00	0.00	1,997,619.00	(1,997,619.00)	-202.26%	-53.48%	-45.94%	-35.32%	-45.57%	-45.55%	-51.06%	-51.63%	-56.38%	-57.28%	
353.1	2009	2,271,500.42	0.00	3,712,389.00	(3,712,389.00)	-163.43%	-175.20%	-86.95%	-53.22%	-64.52%	-61.13%	-60.05%	-64.09%	-64.54%	-68.75%	
353.1	2010	4,105,979.06	0.00	4,939,347.67	(4,939,347.67)	-120.30%	-135.66%	-144.59%	-92.06%	-81.05%	-76.40%	-72.53%	-71.00%	-73.83%	-74.18%	
353.1	2011	1,690,734.88	22,000.00	4,631,935.57	(4,609,935.57)	-272.66%	-164.74%	-164.37%	-146.44%	-120.96%	-99.06%	-92.22%	-87.24%	-85.05%	-87.07%	
353.1	2012	3,516,525.62	3,992.80	4,907,121.67	(4,903,128.87)	-139.43%	-182.69%	-155.18%	-124.75%	-160.37%	-124.83%	-105.66%	-99.00%	-94.16%	-91.93%	
353.1	2013	3,146,190.52	151,500.00	2,710,741.90	(2,559,241.90)	-81.34%	-112.00%	-144.52%	-96.89%	-140.68%	-144.55%	-117.96%	-102.56%	-96.99%	-92.80%	
353.1	2014	4,427,189.71	0.00	1,571,930.84	(1,571,930.84)	-35.51%	-54.55%	-81.46%	-70.69%	-110.05%	-116.38%	-120.59%	-102.97%	-92.35%	-88.50%	
353.1	2015	1,595,058.73	0.00	2,094,411.01	(2,094,411.01)	-131.31%	-60.88%	-67.90%	-49.08%	-109.48%	-111.88%	-117.53%	-121.38%	-104.71%	-94.38%	
353.1	2016	2,919,116.92	0.00	3,598,037.17	(3,598,037.17)	-123.26%	-126.10%	-81.24%	-60.10%	-94.38%	-111.81%	-113.44%	-118.23%	-121.60%	-106.59%	
353.1	2017	436,692.00	0.00	3,720,910.89	(3,720,910.89)	-852.07%	-218.10%	-190.14%	-100.38%	-108.15%	-115.00%	-130.04%	-128.21%	-131.52%	-134.31%	
353.2	1991	0.00	0.00	0.00	0.00	NA										
353.2	1992	0.00	0.00	0.00	0.00	NA	NA									
353.2	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
353.2	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
353.2	1995	13,133.46	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%						
353.2	1996	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%					
353.2	1997	12,512.08	4,159.81	12,641.95	(8,482.14)	-67.79%	-67.79%	-33.07%	-33.07%	-33.07%	-33.07%	-33.07%				
353.2	1998	11,090.68	0.00	0.00	0.00	0.00%	-35.94%	-35.94%	-23.09%	-23.09%	-23.09%	-23.09%	-23.09%			
353.2	1999	0.00	0.00	0.00	0.00	NA	0.00%	-35.94%	-35.94%	-23.09%	-23.09%	-23.09%	-23.09%	-23.09%		
353.2	2000	0.00	0.00	43,250.62	(43,250.62)	NA	NA	-389.97%	-183.24%	-219.18%	-140.82%	-140.82%	-140.82%	-140.82%	-140.82%	
353.2	2001	56,045.20	0.00	9,369.81	(9,369.81)	-16.72%	-93.89%	-93.89%	-78.38%	-76.72%	-76.72%	-65.86%	-65.86%	-65.86%	-65.86%	
353.2	2002	396,431.93	0.00	196,131.18	(196,131.18)	-49.47%	-45.42%	-54.98%	-54.98%	-53.66%	-54.03%	-54.03%	-52.58%	-52.58%	-52.58%	
353.2	2003	0.00	0.00	0.00	0.00	NA	-49.47%	-45.42%	-45.42%	-54.98%	-53.66%	-54.03%	-54.03%	-52.58%	-52.58%	
353.2	2004	614,671.34	0.00	16,382.07	(16,382.07)	-2.67%	-2.67%	-21.02%	-19.91%	-24.85%	-24.85%	-24.59%	-25.09%	-25.09%	-24.79%	
353.2	2005	1,389,477.68	0.00	752,752.59	(752,752.59)	-54.18%	-38.38%	-38.38%	-32.04%	-39.67%	-41.43%	-41.43%	-41.25%	-41.38%	-41.38%	
353.2	2006	2,870,462.00	0.00	383,705.00	(383,705.00)	-13.37%	-26.68%	-23.65%	-23.65%	-25.59%	-25.50%	-26.31%	-26.31%	-26.26%	-26.35%	
353.2	2007	274,994.00	0.00	192,029.00	(192,029.00)	-69.83%	-18.30%	-29.29%	-25.80%	-26.12%	-27.79%	-27.67%	-28.45%	-28.45%	-28.39%	
353.2	2008	9,227.00	0.00	48,933.00	(48,933.00)	-530.32%	-84.78%	-19.80%	-13.75%	-27.02%	-27.02%	-28.62%	-28.50%	-29.27%	-29.27%	
353.2	2009	195,074.71	0.00	296,560.00	(296,560.00)	-152.02%	-169.11%	-112.15%	-16.05%	-35.32%	-31.57%	-31.57%	-32.81%	-32.65%	-33.40%	
353.2	2010	1,353,653.81	0.00	1,040,642.49	(1,040,642.49)	-76.88%	-86.34%	-88.97%	-75.62%	-41.71%	-44.55%	-40.72%	-40.72%	-41.20%	-41.01%	
353.2	2011	1,217,654.55	800.00	2,071,367.96	(2,070,567.96)	-170.05%	-121.00%	-123.19%	-122.78%	-119.61%	-68.10%	-65.46%	-60.59%	-60.59%	-60.06%	
353.2	2012	10,082.72	0.00	119,056.73	(119,056.73)	-1180.80%	-178.35%	-125.14%	-116.34%	-128.36%	-123.10%	-69.99%	-66.99%	-62.01%	-62.01%	
353.2	2013	2,197,504.58	0.00	2,219,369.25	(2,219,369.25)	-100.99%	-105.93%	-128.72%	-92.26%	-115.53%	-116.29%	-113.86%	-78.38%	-74.84%	-70.46%	
353.2	2014	38,781.51	0.00	513,113.58	(513,113.58)	-1323.09%	-122.19%	-126.94%	-82.32%	-123.77%	-124.87%	-125.61%	-122.72%	-84.29%	-79.91%	
353.2	2015	956,361.73	0.00	291,723.73	(291,723.73)	-30.50%	-80.88%	-94.72%	-94.43%	-117.95%	-108.32%	-109.75%	-110.40%	-108.61%	-78.65%	
353.2	2016	7,486,842.15	0.00	747,322.43	(747,322.43)	-9.98%	-12.31%	-18.30%	-14.53%	-36.40%	-50.06%	-52.80%	-54.24%	-54.57%	-54.87%	
353.2	2017	601,133.78	0.00	656,824.03	(656,824.03)	-109.26%	-17.36%	-18.75%	-18.67%	-39.26%	-40.28%	-52.91%	-55.25%	-56.59%	-56.90%	
353.4	1991	0.00	0.00	0.00	0.00	NA										
353.4	1992	0.00	0.00	0.00	0.00	NA	NA									
353.4	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
353.4	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
353.4	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
353.4	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
353.4	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
353.4	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
353.4	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		

SAN DIEGO GAS AND ELECTRIC T05
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Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
353.4	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.4	2013	179,607.12	0.00	9,096.00	(9,096.00)	-5.06%	-5.06%	-5.06%	-5.06%	-5.06%	-5.06%	-5.06%	-5.06%	-5.06%	-5.06%	
353.4	2014	0.00	0.00	1,123.11	(1,123.11)	NA	-5.69%	-5.69%	-5.69%	-5.69%	-5.69%	-5.69%	-5.69%	-5.69%	-5.69%	
353.4	2015	0.00	0.00	1,675.50	(1,675.50)	NA	NA	-6.62%	-6.62%	-6.62%	-6.62%	-6.62%	-6.62%	-6.62%	-6.62%	
353.4	2016	0.00	0.00	2,049.46	(2,049.46)	NA	NA	NA	-2.70%	-7.76%	-7.76%	-7.76%	-7.76%	-7.76%	-7.76%	
353.4	2017	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-7.76%	-7.76%	-7.76%	-7.76%	-7.76%	-7.76%	
353.6	1991	0.00	0.00	0.00	0.00	NA										
353.6	1992	0.00	0.00	0.00	0.00	NA	NA									
353.6	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
353.6	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
353.6	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
353.6	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
353.6	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
353.6	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
353.6	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
353.6	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2014	0.00	0.00	(478.71)	478.71	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2015	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2016	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
353.6	2017	0.00	0.00	14,432.08	(14,432.08)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E353 Total	1991	1,867,476.00	41,903.00	373,394.00	(331,491.00)	-17.75%										
E353 Total	1992	271,058.00	99,669.00	71,325.00	28,344.00	10.46%	-14.18%									
E353 Total	1993	797,673.00	88,966.00	178,438.00	(89,472.00)	-11.22%	-5.72%	-13.37%								
E353 Total	1994	439,382.00	76,179.00	34,179.00	42,000.00	9.56%	-3.84%	-1.27%	-10.39%							
E353 Total	1995	773,685.71	193,776.00	77,299.00	116,477.00	15.05%	13.06%	3.43%	4.27%	-5.64%						
E353 Total	1996	138,398.00	0.00	65,582.00	(65,582.00)	-47.39%	5.58%	6.87%	0.16%	1.31%	-6.99%					
E353 Total	1997	186,456.99	103,115.38	138,803.14	(35,687.76)	-19.14%	-31.17%	1.38%	3.72%	-1.38%	-0.15%	-7.50%				
E353 Total	1998	281,907.66	0.00	47,872.53	(47,872.53)	-16.98%	-17.84%	-24.58%	-2.37%	0.51%	-3.06%	-1.79%	-8.06%			
E353 Total	1999	74,152.87	0.00	198,810.69	(198,810.69)	-268.11%	-69.28%	-52.05%	-51.10%	-15.91%	-10.00%	-10.36%	-8.46%	-12.05%		
E353 Total	2000	0.00	0.00	869,634.52	(869,634.52)	NA	-1440.87%	-313.52%	-205.77%	-178.82%	-75.70%	-55.92%	-42.67%	-37.81%	-30.06%	
E353 Total	2001	124,962.14	0.00	142,850.24	(142,850.24)	-114.31%	-810.23%	-608.34%	-251.82%	-193.99%	-168.81%	-78.75%	-59.53%	-45.85%	-40.91%	
E353 Total	2002	1,509,151.99	40,047.56	1,696,730.37	(1,656,682.81)	-109.78%	-110.12%	-163.34%	-156.25%	-146.51%	-135.60%	-130.33%	-93.91%	-81.03%	-68.15%	

SAN DIEGO GAS AND ELECTRIC T05
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AS ADJUSTED
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Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
E353 Total	2003	1,268,550.57	20,005.08	594,818.21	(574,813.13)	-45.31%	-80.34%	-81.80%	-81.80%	-115.65%	-107.12%	-102.36%	-100.23%	-79.76%	-71.58%	
E353 Total	2004	2,647,753.23	750.00	745,474.72	(744,724.72)	-28.13%	-33.69%	-54.86%	-53.62%	-71.86%	-74.45%	-71.71%	-70.10%	-69.59%	-60.25%	
E353 Total	2005	4,373,168.99	0.00	2,274,139.08	(2,274,139.08)	-52.00%	-43.00%	-43.35%	-36.68%	-54.35%	-63.11%	-64.63%	-63.32%	-62.54%	-62.34%	
E353 Total	2006	7,600,326.00	0.00	2,165,630.00	(2,165,630.00)	-28.49%	-37.08%	-35.46%	-32.63%	-42.62%	-43.13%	-48.10%	-49.02%	-48.52%	-48.22%	
E353 Total	2007	4,477,291.00	0.00	969,952.00	(969,952.00)	-21.66%	-25.96%	-32.88%	-28.33%	-33.04%	-38.33%	-38.77%	-42.72%	-43.47%	-43.14%	
E353 Total	2008	996,899.00	0.00	2,046,552.00	(2,046,552.00)	-205.29%	-55.10%	-39.64%	-29.70%	-40.81%	-41.08%	-45.61%	-45.98%	-49.76%	-50.47%	
E353 Total	2009	2,466,575.13	0.00	4,008,949.00	(4,008,949.00)	-162.53%	-174.84%	-88.47%	-45.21%	-57.57%	-54.12%	-53.65%	-56.99%	-57.27%	-60.69%	
E353 Total	2010	5,459,632.87	0.00	5,979,990.16	(5,979,990.16)	-109.53%	-126.02%	-134.88%	-89.81%	-72.24%	-68.75%	-64.91%	-64.06%	-66.30%	-66.50%	
E353 Total	2011	2,908,389.43	22,800.00	6,703,303.53	(6,680,503.53)	-229.70%	-151.30%	-153.85%	-140.89%	-120.71%	-91.39%	-85.30%	-80.41%	-79.03%	-80.40%	
E353 Total	2012	3,526,608.34	3,992.80	5,026,178.40	(5,022,185.60)	-142.41%	-181.86%	-148.66%	-123.13%	-154.56%	-124.57%	-97.95%	-91.63%	-86.75%	-85.28%	
E353 Total	2013	5,523,302.22	151,500.00	4,939,207.15	(4,787,707.15)	-86.68%	-108.40%	-137.90%	-94.67%	-133.17%	-136.61%	-116.31%	-96.06%	-90.90%	-86.74%	
E353 Total	2014	4,465,971.22	0.00	2,085,688.82	(2,085,688.82)	-46.70%	-68.81%	-88.01%	-72.43%	-112.21%	-117.31%	-120.77%	-105.89%	-90.17%	-86.18%	
E353 Total	2015	2,551,420.46	0.00	2,387,810.24	(2,387,810.24)	-93.59%	-63.75%	-73.85%	-57.64%	-110.48%	-110.27%	-115.06%	-118.28%	-104.92%	-90.39%	
E353 Total	2016	10,405,959.07	0.00	4,347,409.06	(4,347,409.06)	-41.78%	-51.98%	-50.63%	-38.44%	-70.38%	-86.15%	-89.81%	-94.62%	-97.50%	-89.56%	
E353 Total	2017	1,037,825.78	0.00	4,392,167.00	(4,392,167.00)	-423.21%	-76.37%	-79.51%	-60.27%	-75.05%	-83.69%	-97.65%	-99.45%	-103.51%	-106.09%	-81.17%
354.1	1991	57,786.00	0.00	6,142.00	(6,142.00)	-10.63%										
354.1	1992	0.00	0.00	20.00	(20.00)	NA	-10.66%									
354.1	1993	0.00	0.00	1,397.00	(1,397.00)	NA	NA	-13.08%								
354.1	1994	0.00	0.00	237.00	(237.00)	NA	NA	NA	-13.49%							
354.1	1995	17,909.00	0.00	89.00	(89.00)	-0.50%	-1.82%	-9.62%	-9.73%	-10.42%						
354.1	1996	9,652.00	0.00	43,573.00	(43,573.00)	-451.44%	-158.42%	-159.28%	-164.35%	-164.42%	-60.29%					
354.1	1997	74,166.00	0.00	22,876.00	(22,876.00)	-30.84%	-79.28%	-65.41%	-65.64%	-67.01%	-67.03%	-46.60%				
354.1	1998	64,024.00	0.00	22,369.00	(22,369.00)	-34.94%	-32.74%	-60.08%	-53.64%	-53.78%	-54.62%	-54.64%	-43.26%			
354.1	1999	73,659.73	0.00	10,903.77	(10,903.77)	-14.80%	-24.17%	-26.50%	-45.02%	-41.69%	-41.79%	-42.37%	-42.38%	-36.21%		
354.1	2000	0.00	0.00	21,515.20	(21,515.20)	NA	-44.01%	-39.79%	-25.86%	-54.73%	-50.68%	-50.78%	-51.36%	-51.37%	-43.45%	
354.1	2001	18,840.00	0.00	16,155.00	(16,155.00)	-85.75%	-199.95%	-52.51%	-31.03%	-40.67%	-57.17%	-53.24%	-53.33%	-53.87%	-53.88%	
354.1	2002	0.00	0.00	0.00	0.00	NA	-85.75%	-199.95%	-40.72%	-45.32%	-40.67%	-57.17%	-53.24%	-53.33%	-53.87%	
354.1	2003	0.00	0.00	0.00	0.00	NA	NA	-85.75%	-85.75%	-52.51%	-45.32%	-40.67%	-57.17%	-53.24%	-53.33%	
354.1	2004	27,604.29	0.00	109,130.62	(109,130.62)	-395.34%	-395.34%	-395.34%	-234.97%	-316.08%	-131.31%	-97.80%	-78.57%	-92.00%	-86.27%	
354.1	2005	0.00	0.00	15,171.00	(15,171.00)	NA	-450.30%	-450.30%	-450.30%	-302.42%	-348.74%	-143.94%	-106.04%	-84.45%	-97.67%	
354.1	2006	0.00	0.00	0.00	0.00	NA	NA	-450.30%	-450.30%	-450.30%	-302.42%	-348.74%	-143.94%	-106.04%	-84.45%	
354.1	2007	17,203.00	0.00	24,346.00	(24,346.00)	-141.52%	-141.52%	-229.71%	-88.19%	-331.75%	-331.75%	-258.93%	-292.73%	-143.64%	-109.07%	
354.1	2008	47,688.00	0.00	155,138.00	(155,138.00)	-325.32%	-276.59%	-276.59%	-276.59%	-328.43%	-328.43%	-328.43%	-287.37%	-306.69%	-190.47%	
354.1	2009	249,646.00	0.00	768,892.00	(768,892.00)	-307.99%	-310.77%	-301.51%	-301.51%	-306.34%	-313.52%	-313.52%	-313.52%	-301.63%	-307.59%	
354.1	2010	3,645.02	0.00	136,428.14	(136,428.14)	-3742.86%	-357.42%	-352.34%	-333.29%	-340.94%	-345.71%	-349.67%	-349.67%	-349.67%	-336.03%	
354.1	2011	3,673.94	0.00	46,182.55	(46,182.55)	-1257.03%	-2495.04%	-370.28%	-312.32%	-351.40%	-351.40%	-356.11%	-359.21%	-359.21%	-359.21%	
354.1	2012	0.00	0.00	2,014.15	(2,014.15)	NA	-1311.85%	-2522.56%	-71.85%	-363.91%	-352.02%	-352.02%	-356.73%	-359.78%	-359.78%	
354.1	2013	0.00	0.00	0.00	0.00	NA	NA	-1311.85%	-658.52%	-371.07%	-363.91%	-352.02%	-352.02%	-356.73%	-359.78%	
354.1	2014	0.00	0.00	88,227.12	(88,227.12)	NA	NA	NA	-2456.25%	-3728.02%	-405.40%	-392.87%	-379.43%	-379.43%	-384.15%	
354.1	2015	0.00	0.00	77,675.54	(77,675.54)	NA	NA	NA	NA	-5827.51%	-4789.31%	-435.63%	-418.36%	-403.57%	-403.57%	
354.1	2016	0.00	0.00	602,305.42	(602,305.42)	NA	NA	NA	NA	NA	-22221.51%	-13018.69%	-670.02%	-616.07%	-590.70%	
354.1	2017	0.00	0.00	409,338.00	(409,338.00)	NA	NA	NA	NA	NA	NA	-33363.17%	-18611.54%	-829.32%	-750.43%	
354.2	1991	0.00	0.00	0.00	0.00	NA										
354.2	1992	0.00	0.00	0.00	0.00	NA	NA									
354.2	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
354.2	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
354.2	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
354.2	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
354.2	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
354.2	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
354.2	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
354.2	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	

SAN DIEGO GAS AND ELECTRIC T05
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Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
354.2	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2015	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2016	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.2	2017	0.00	0.00	22,519.77	(22,519.77)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	1991	0.00	0.00	0.00	0.00	NA										
354.6	1992	0.00	0.00	0.00	0.00	NA	NA									
354.6	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
354.6	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
354.6	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
354.6	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
354.6	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
354.6	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
354.6	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
354.6	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2015	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2016	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
354.6	2017	0.00	0.00	156.22	(156.22)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E354 Total	1991	57,786.00	0.00	6,142.00	(6,142.00)	-10.63%										
E354 Total	1992	0.00	0.00	20.00	(20.00)	NA	-10.66%									
E354 Total	1993	0.00	0.00	1,397.00	(1,397.00)	NA	NA	-13.08%								
E354 Total	1994	0.00	0.00	237.00	(237.00)	NA	NA	NA	-13.49%							
E354 Total	1995	17,909.00	0.00	89.00	(89.00)	-0.50%	-1.82%	-9.62%	-9.73%	-10.42%						
E354 Total	1996	9,652.00	0.00	43,573.00	(43,573.00)	-451.44%	-158.42%	-159.28%	-164.35%	-164.42%	-60.29%					
E354 Total	1997	74,166.00	0.00	22,876.00	(22,876.00)	-30.84%	-79.28%	-65.41%	-65.64%	-67.01%	-67.03%	-46.60%				
E354 Total	1998	64,024.00	0.00	22,369.00	(22,369.00)	-34.94%	-32.74%	-60.08%	-53.64%	-53.78%	-54.62%	-54.64%	-43.26%			
E354 Total	1999	73,659.73	0.00	10,903.77	(10,903.77)	-14.80%	-24.17%	-26.50%	-45.02%	-41.69%	-41.79%	-42.37%	-42.38%	-36.21%		
E354 Total	2000	0.00	0.00	21,515.20	(21,515.20)	NA	-44.01%	-39.79%	-25.86%	-54.73%	-50.68%	-50.78%	-51.36%	-51.37%	-43.45%	
E354 Total	2001	18,840.00	0.00	16,155.00	(16,155.00)	-85.75%	-199.95%	-52.51%	-31.03%	-40.67%	-57.17%	-53.24%	-53.33%	-53.87%	-53.88%	
E354 Total	2002	0.00	0.00	0.00	0.00	NA	-85.75%	-199.95%	-40.72%	-45.32%	-40.67%	-57.17%	-53.24%	-53.33%	-53.87%	
E354 Total	2003	0.00	0.00	0.00	0.00	NA	NA	-85.75%	-85.75%	-52.51%	-45.32%	-40.67%	-57.17%	-53.24%	-53.33%	
E354 Total	2004	27,604.29	0.00	109,130.62	(109,130.62)	-395.34%	-395.34%	-395.34%	-234.97%	-316.08%	-131.31%	-97.80%	-78.57%	-92.00%	-86.27%	
E354 Total	2005	0.00	0.00	15,171.00	(15,171.00)	NA	-450.30%	-450.30%	-450.30%	-302.42%	-348.74%	-143.94%	-106.04%	-84.45%	-97.67%	
E354 Total	2006	0.00	0.00	0.00	0.00	NA	NA	-450.30%	-450.30%	-450.30%	-302.42%	-348.74%	-143.94%	-106.04%	-84.45%	
E354 Total	2007	17,203.00	0.00	24,346.00	(24,346.00)	-141.52%	-141.52%	-229.71%	-88.19%	-331.75%	-331.75%	-258.93%	-292.73%	-143.64%	-109.07%	
E354 Total	2008	47,688.00	0.00	155,138.00	(155,138.00)	-325.32%	-276.59%	-276.59%	-276.59%	-328.43%	-328.43%	-328.43%	-287.37%	-306.69%	-190.47%	

SAN DIEGO GAS AND ELECTRIC T05
RETIREMENT AND NET SALVAGE
AS ADJUSTED
DATA THROUGH DECEMBER 2017

Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
E354 Total	2009	249,646.00	0.00	768,892.00	(768,892.00)	-307.99%	-310.77%	-301.51%	-301.51%	-306.34%	-313.52%	-313.52%	-313.52%	-301.63%	-307.59%	
E354 Total	2010	3,645.02	0.00	136,428.14	(136,428.14)	-3742.86%	-357.42%	-352.34%	-333.29%	-340.94%	-345.71%	-349.67%	-349.67%	-349.67%	-336.03%	
E354 Total	2011	3,673.94	0.00	46,182.55	(46,182.55)	-1257.03%	-2495.04%	-370.28%	-312.32%	-351.40%	-351.40%	-356.11%	-359.21%	-359.21%	-359.21%	
E354 Total	2012	0.00	0.00	2,014.15	(2,014.15)	NA	-1311.85%	-2522.56%	-71.85%	-363.91%	-352.02%	-352.02%	-356.73%	-359.78%	-359.78%	
E354 Total	2013	0.00	0.00	0.00	0.00	NA	NA	-1311.85%	-658.52%	-371.07%	-363.91%	-352.02%	-352.02%	-356.73%	-359.78%	
E354 Total	2014	0.00	0.00	88,227.12	(88,227.12)	NA	NA	NA	-2456.25%	-3728.02%	-405.40%	-392.87%	-379.43%	-379.43%	-384.15%	
E354 Total	2015	0.00	0.00	77,675.54	(77,675.54)	NA	NA	NA	NA	-5827.51%	-4789.31%	-435.63%	-418.36%	-403.57%	-403.57%	
E354 Total	2016	0.00	0.00	602,305.42	(602,305.42)	NA	NA	NA	NA	NA	-22221.51%	-13018.69%	-670.02%	-616.07%	-590.70%	
E354 Total	2017	0.00	0.00	432,013.99	(432,013.99)	NA	NA	NA	NA	NA	NA	-33980.38%	-18921.36%	-838.14%	-757.87%	-703.23%
355.1	1991	123,451.00	32,194.00	86,390.00	(54,196.00)	-43.90%										
355.1	1992	80,254.00	3,835.00	328,318.00	(324,483.00)	-404.32%	-185.90%									
355.1	1993	185,734.00	22,031.00	224,499.00	(202,468.00)	-109.01%	-198.11%	-149.23%								
355.1	1994	244,670.00	5,095.00	164,887.00	(159,792.00)	-65.31%	-84.17%	-134.48%	-116.85%							
355.1	1995	535,840.00	12,227.00	83,240.00	(71,013.00)	-13.25%	-29.57%	-44.84%	-72.41%	-69.40%						
355.1	1996	140,763.00	858.00	181,243.00	(180,385.00)	-128.15%	-37.16%	-44.63%	-55.43%	-79.02%	-75.71%					
355.1	1997	107,181.00	0.00	141,223.00	(141,223.00)	-131.76%	-129.71%	-50.09%	-53.71%	-62.17%	-83.38%	-79.95%				
355.1	1998	265,935.00	0.00	237,391.00	(237,391.00)	-89.27%	-101.47%	-108.78%	-60.02%	-61.02%	-67.04%	-84.39%	-81.42%			
355.1	1999	1,668,297.86	0.00	581,269.78	(581,269.78)	-34.84%	-42.32%	-47.02%	-52.25%	-44.56%	-46.28%	-49.98%	-58.79%	-58.24%		
355.1	2000	838,408.00	0.00	744,770.50	(744,770.50)	-88.83%	-52.90%	-56.39%	-54.29%	-62.41%	-55.00%	-55.66%	-58.15%	-64.98%	-64.36%	
355.1	2001	976,466.00	0.00	503,889.47	(503,889.47)	-51.60%	-68.80%	-52.54%	-48.81%	-57.27%	-59.77%	-54.27%	-54.83%	-56.86%	-62.39%	
355.1	2002	1,237,299.53	557.05	884,641.58	(884,084.53)	-71.45%	-62.70%	-69.88%	-45.18%	-59.19%	-60.72%	-62.53%	-57.95%	-58.25%	-59.77%	
355.1	2003	1,071,234.09	0.00	1,639,556.43	(1,639,556.43)	-153.05%	-109.32%	-92.16%	-73.42%	-75.17%	-75.79%	-76.76%	-77.91%	-72.84%	-72.58%	
355.1	2004	2,081,011.88	0.00	1,508,638.74	(1,508,638.74)	-72.50%	-99.87%	-91.86%	-75.14%	-85.12%	-74.46%	-74.95%	-75.68%	-76.57%	-72.76%	
355.1	2005	1,115,315.40	0.00	1,182,133.30	(1,182,133.30)	-105.99%	-84.18%	-101.47%	-78.66%	-88.23%	-88.30%	-78.37%	-78.69%	-79.30%	-80.02%	
355.1	2006	1,059,406.00	39,314.00	403,451.00	(364,137.00)	-34.37%	-71.10%	-71.78%	-57.35%	-84.98%	-80.66%	-81.48%	-73.74%	-74.14%	-74.73%	
355.1	2007	3,055,924.00	0.00	1,568,166.00	(1,568,166.00)	-51.32%	-46.95%	-59.54%	-42.60%	-74.71%	-74.29%	-72.20%	-73.42%	-68.51%	-68.92%	
355.1	2008	2,918,403.00	0.00	2,735,759.00	(2,735,759.00)	-93.74%	-72.04%	-66.37%	-57.28%	-71.93%	-79.62%	-78.82%	-76.85%	-77.55%	-73.10%	
355.1	2009	2,472,487.00	1,066.00	5,592,418.00	(5,591,352.00)	-226.14%	-154.47%	-117.15%	-104.09%	-107.72%	-101.95%	-105.92%	-103.08%	-99.94%	-99.39%	
355.1	2010	2,067,527.14	(1,062.00)	1,695,944.01	(1,697,006.01)	-82.08%	-160.54%	-134.40%	-95.34%	-103.31%	-103.54%	-99.17%	-102.81%	-100.54%	-97.89%	
355.1	2011	1,739,701.20	0.00	4,914,552.96	(4,914,552.96)	-282.49%	-173.66%	-194.32%	-132.67%	-134.71%	-126.72%	-125.12%	-118.49%	-120.59%	-117.36%	
355.1	2012	638,235.29	0.00	1,083,758.39	(1,083,758.39)	-169.81%	-252.25%	-173.10%	-111.24%	-162.89%	-136.44%	-128.69%	-127.01%	-120.40%	-122.32%	
355.1	2013	2,995,883.59	0.00	1,500,069.72	(1,500,069.72)	-50.07%	-71.10%	-139.54%	-100.77%	-149.15%	-136.55%	-120.16%	-114.79%	-114.25%	-109.94%	
355.1	2014	4,830,872.01	0.00	3,682,242.91	(3,682,242.91)	-76.22%	-66.21%	-74.02%	-61.40%	-104.93%	-125.26%	-120.05%	-109.91%	-106.24%	-106.23%	
355.1	2015	3,590,920.79	0.00	3,716,338.47	(3,716,338.47)	-103.49%	-87.85%	-77.94%	-73.81%	-107.98%	-104.61%	-121.00%	-117.25%	-108.96%	-105.85%	
355.1	2016	2,329,677.78	0.00	5,257,191.86	(5,257,191.86)	-225.66%	-151.56%	-117.71%	-92.06%	-105.94%	-124.98%	-120.11%	-132.80%	-127.96%	-119.17%	
355.1	2017	3,946,996.37	0.00	5,111,989.30	(5,111,989.30)	-129.52%	-165.20%	-142.75%	-95.83%	-108.89%	-111.01%	-125.88%	-121.79%	-132.27%	-128.19%	
355.2	1991	0.00	0.00	0.00	0.00	NA										
355.2	1992	0.00	0.00	0.00	0.00	NA	NA									
355.2	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
355.2	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
355.2	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
355.2	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
355.2	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
355.2	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
355.2	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
355.2	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	

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355.2	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2015	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2016	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.2	2017	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	1991	0.00	0.00	0.00	0.00	NA										
355.6	1992	0.00	0.00	0.00	0.00	NA	NA									
355.6	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
355.6	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
355.6	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
355.6	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
355.6	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
355.6	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
355.6	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
355.6	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2014	0.00	0.00	(24,881.33)	24,881.33	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2015	0.00	0.00	193.35	(193.35)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2016	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
355.6	2017	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E355 Total	1991	123,451.00	32,194.00	86,390.00	(54,196.00)	-43.90%										
E355 Total	1992	80,254.00	3,835.00	328,318.00	(324,483.00)	-404.32%	-185.90%									
E355 Total	1993	185,734.00	22,031.00	224,499.00	(202,468.00)	-109.01%	-198.11%	-149.23%								
E355 Total	1994	244,670.00	5,095.00	164,887.00	(159,792.00)	-65.31%	-84.17%	-134.48%	-116.85%							
E355 Total	1995	535,840.00	12,227.00	83,240.00	(71,013.00)	-13.25%	-29.57%	-44.84%	-72.41%	-69.40%						
E355 Total	1996	140,763.00	858.00	181,243.00	(180,385.00)	-128.15%	-37.16%	-44.63%	-55.43%	-79.02%	-75.71%					
E355 Total	1997	107,181.00	0.00	141,223.00	(141,223.00)	-131.76%	-129.71%	-50.09%	-53.71%	-62.17%	-83.38%	-79.95%				
E355 Total	1998	265,935.00	0.00	237,391.00	(237,391.00)	-89.27%	-101.47%	-108.78%	-60.02%	-61.02%	-67.04%	-84.39%	-81.42%			
E355 Total	1999	1,668,297.86	0.00	581,269.78	(581,269.78)	-34.84%	-42.32%	-47.02%	-52.25%	-44.56%	-46.28%	-49.98%	-58.79%	-58.24%		
E355 Total	2000	838,408.00	0.00	744,770.50	(744,770.50)	-88.83%	-52.90%	-56.39%	-54.29%	-62.41%	-55.00%	-55.66%	-58.15%	-64.98%	-64.36%	
E355 Total	2001	976,466.00	0.00	503,889.47	(503,889.47)	-51.60%	-68.80%	-52.54%	-48.81%	-57.27%	-59.77%	-54.27%	-54.83%	-56.86%	-62.39%	
E355 Total	2002	1,237,299.53	557.05	884,641.58	(884,084.53)	-71.45%	-62.70%	-69.88%	-45.18%	-59.19%	-60.72%	-62.53%	-57.95%	-58.25%	-59.77%	
E355 Total	2003	1,071,234.09	0.00	1,639,556.43	(1,639,556.43)	-153.05%	-109.32%	-92.16%	-73.42%	-75.17%	-75.79%	-76.76%	-77.91%	-72.84%	-72.58%	
E355 Total	2004	2,081,011.88	0.00	1,508,638.74	(1,508,638.74)	-72.50%	-99.87%	-91.86%	-75.14%	-85.12%	-74.46%	-74.95%	-75.68%	-76.57%	-72.76%	
E355 Total	2005	1,115,315.40	0.00	1,182,133.30	(1,182,133.30)	-105.99%	-84.18%	-101.47%	-78.66%	-88.23%	-88.30%	-78.37%	-78.69%	-79.30%	-80.02%	
E355 Total	2006	1,059,406.00	39,314.00	403,451.00	(364,137.00)	-34.37%	-71.10%	-71.78%	-57.35%	-84.98%	-80.66%	-81.48%	-73.74%	-74.14%	-74.73%	
E355 Total	2007	3,055,924.00	0.00	1,568,166.00	(1,568,166.00)	-51.32%	-46.95%	-59.54%	-42.60%	-74.71%	-74.29%	-72.20%	-73.42%	-68.51%	-68.92%	
E355 Total	2008	2,918,403.00	0.00	2,735,759.00	(2,735,759.00)	-93.74%	-72.04%	-66.37%	-57.28%	-71.93%	-79.62%	-78.82%	-76.85%	-77.55%	-73.10%	
E355 Total	2009	2,472,487.00	1,066.00	5,592,418.00	(5,591,352.00)	-226.14%	-154.47%	-117.15%	-104.09%	-107.72%	-101.95%	-105.92%	-103.08%	-99.94%	-99.39%	
E355 Total	2010	2,067,527.14	(1,062.00)	1,695,944.01	(1,697,006.01)	-82.08%	-160.54%	-134.40%	-95.34%	-103.31%	-103.54%	-99.17%	-102.81%	-100.54%	-97.89%	
E355 Total	2011	1,739,701.20	0.00	4,914,552.96	(4,914,552.96)	-282.49%	-173.66%	-194.32%	-132.67%	-134.71%	-126.72%	-125.12%	-118.49%	-120.59%	-117.36%	
E355 Total	2012	638,235.29	0.00	1,083,758.39	(1,083,758.39)	-169.81%	-252.25%	-173.10%	-111.24%	-162.89%	-136.44%	-128.69%	-127.01%	-120.40%	-122.32%	
E355 Total	2013	2,995,883.59	0.00	1,500,069.72	(1,500,069.72)	-50.07%	-71.10%	-139.54%	-100.77%	-149.15%	-136.55%	-120.16%	-114.79%	-114.25%	-109.94%	
E355 Total	2014	4,830,872.01	0.00	3,657,361.58	(3,657,361.58)	-75.71%	-65.89%	-73.73%	-61.16%	-104.73%	-125.09%	-119.91%	-109.79%	-106.12%	-106.12%	

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E355 Total	2015	3,590,920.79	0.00	3,716,531.82	(3,716,531.82)	-103.50%	-87.56%	-77.72%	-73.61%	-107.80%	-104.45%	-120.86%	-117.14%	-108.86%	-105.75%	
E355 Total	2016	2,329,677.78	0.00	5,257,191.86	(5,257,191.86)	-225.66%	-151.57%	-117.48%	-91.88%	-105.76%	-124.83%	-119.97%	-132.68%	-127.86%	-119.08%	
E355 Total	2017	3,946,996.37	0.00	5,111,989.30	(5,111,989.30)	-129.52%	-165.20%	-142.75%	-95.83%	-108.75%	-110.88%	-125.75%	-121.67%	-132.17%	-128.10%	-115.63%
356.1	1991	154,699.00	47,289.00	143,037.00	(95,748.00)	-61.89%										
356.1	1992	94,405.00	1,264.00	446,070.00	(444,806.00)	-471.17%	-217.00%									
356.1	1993	430,142.00	34,563.00	303,392.00	(268,829.00)	-62.50%	-136.05%	-119.16%								
356.1	1994	532,104.00	7,343.00	148,359.00	(141,016.00)	-26.50%	-42.59%	-80.88%	-78.46%							
356.1	1995	1,483,725.00	0.00	199,246.00	(199,246.00)	-13.43%	-16.88%	-24.90%	-41.49%	-42.66%						
356.1	1996	200,223.00	6.00	258,821.00	(258,815.00)	-129.26%	-27.20%	-27.03%	-32.80%	-47.90%	-48.65%					
356.1	1997	84,062.00	0.00	161,438.00	(161,438.00)	-192.05%	-147.83%	-35.04%	-33.06%	-37.70%	-52.19%	-52.69%				
356.1	1998	200,822.00	0.00	335,680.00	(335,680.00)	-167.15%	-174.50%	-155.83%	-48.52%	-43.83%	-46.57%	-59.82%	-59.92%			
356.1	1999	965,652.64	0.00	787,321.33	(787,321.33)	-81.53%	-96.27%	-102.71%	-106.38%	-59.38%	-54.33%	-55.23%	-65.07%	-64.95%		
356.1	2000	308,809.00	0.00	1,049,111.34	(1,049,111.34)	-339.73%	-144.09%	-147.23%	-139.30%	-147.33%	-86.07%	-77.68%	-76.12%	-84.80%	-84.00%	
356.1	2001	1,340,342.00	0.00	1,877,240.03	(1,877,240.03)	-140.06%	-177.45%	-142.02%	-131.90%	-145.22%	-144.18%	-101.86%	-94.02%	-91.58%	-97.93%	
356.1	2002	1,154,357.07	557.05	648,294.50	(647,737.45)	-56.11%	-101.21%	-127.49%	-94.82%	-118.32%	-119.84%	-120.29%	-92.66%	-87.04%	-85.47%	
356.1	2003	496,330.09	0.00	802,270.12	(802,270.12)	-161.64%	-87.84%	-111.24%	-100.83%	-121.06%	-123.13%	-124.40%	-124.61%	-98.15%	-92.51%	
356.1	2004	1,638,423.59	0.00	966,798.60	(966,798.60)	-59.01%	-82.87%	-73.48%	-52.21%	-108.20%	-103.84%	-105.92%	-107.09%	-107.79%	-90.00%	
356.1	2005	491,180.60	0.00	833,998.37	(833,998.37)	-169.79%	-84.56%	-99.13%	-68.86%	-100.14%	-113.77%	-108.90%	-110.68%	-111.70%	-112.21%	
356.1	2006	1,065,253.00	321,097.00	164,721.00	156,376.00	14.68%	-43.54%	-51.47%	-44.55%	-63.86%	-80.37%	-92.70%	-91.26%	-93.25%	-94.32%	
356.1	2007	845,162.00	0.00	758,275.00	(758,275.00)	-89.72%	-31.51%	-59.79%	-35.54%	-70.65%	-67.70%	-81.49%	-92.36%	-91.10%	-92.90%	
356.1	2008	904,122.00	0.00	631,669.00	(631,669.00)	-69.87%	-79.46%	-43.83%	-37.32%	-61.37%	-70.52%	-68.00%	-80.17%	-89.89%	-89.02%	
356.1	2009	667,649.00	0.00	1,338,898.00	(1,338,898.00)	-200.54%	-125.37%	-112.91%	-78.37%	-85.73%	-77.93%	-84.73%	-80.18%	-89.51%	-98.18%	
356.1	2010	935,893.62	0.00	1,537,856.48	(1,537,856.48)	-164.32%	-179.40%	-139.91%	-104.64%	-93.03%	-100.71%	-90.28%	-95.31%	-89.79%	-96.85%	
356.1	2011	868,849.74	0.00	3,052,944.51	(3,052,944.51)	-351.38%	-254.37%	-239.84%	-175.62%	-173.38%	-135.49%	-138.41%	-120.87%	-123.42%	-114.85%	
356.1	2012	38,282.70	0.00	383,155.73	(383,155.73)	-1000.86%	-378.79%	-269.88%	-198.11%	-203.37%	-180.82%	-141.71%	-144.08%	-125.38%	-127.65%	
356.1	2013	307,764.84	0.00	303,727.47	(303,727.47)	-98.69%	-198.49%	-307.83%	-173.88%	-234.76%	-194.71%	-175.28%	-139.36%	-141.80%	-124.33%	
356.1	2014	1,139,700.09	0.00	2,743,047.02	(2,743,047.02)	-240.68%	-210.49%	-230.86%	-145.67%	-243.75%	-236.47%	-205.49%	-188.34%	-156.41%	-157.32%	
356.1	2015	168,069.62	0.00	2,626,253.90	(2,626,253.90)	-1562.60%	-410.57%	-351.15%	-343.03%	-361.09%	-307.84%	-290.48%	-250.83%	-227.65%	-190.46%	
356.1	2016	466,006.20	0.00	2,794,657.63	(2,794,657.63)	-599.70%	-854.93%	-460.26%	-392.21%	-417.53%	-398.30%	-342.50%	-321.86%	-280.41%	-254.99%	
356.1	2017	551,113.55	0.00	3,066,919.49	(3,066,919.49)	-556.50%	-576.29%	-716.16%	-365.09%	-438.14%	-446.20%	-422.93%	-368.85%	-347.00%	-305.57%	
356.2	1991	0.00	0.00	0.00	0.00	NA										
356.2	1992	0.00	0.00	0.00	0.00	NA	NA									
356.2	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
356.2	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
356.2	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
356.2	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
356.2	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
356.2	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
356.2	1999	508.28	0.00	0.00	0.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
356.2	2000	0.00	0.00	0.00	0.00	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
356.2	2001	0.00	0.00	0.00	0.00	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
356.2	2002	0.00	0.00	0.00	0.00	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
356.2	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
356.2	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	
356.2	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	0.00%	
356.2	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	0.00%	
356.2	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	0.00%	
356.2	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00%	
356.2	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.2	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.2	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.2	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.2	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.2	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.2	2015	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.2	2016	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.2	2017	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	

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Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
356.6	1991	0.00	0.00	0.00	0.00	NA										
356.6	1992	0.00	0.00	0.00	0.00	NA	NA									
356.6	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
356.6	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
356.6	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
356.6	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
356.6	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
356.6	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
356.6	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
356.6	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2014	0.00	0.00	22,132.20	(22,132.20)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2015	0.00	0.00	5,863.63	(5,863.63)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2016	0.00	0.00	357,253.37	(357,253.37)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
356.6	2017	0.00	0.00	1,896.43	(1,896.43)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E356 Total	1991	154,699.00	47,289.00	143,037.00	(95,748.00)	-61.89%										
E356 Total	1992	94,405.00	1,264.00	446,070.00	(444,806.00)	-471.17%	-217.00%									
E356 Total	1993	430,142.00	34,563.00	303,392.00	(268,829.00)	-62.50%	-136.05%	-119.16%								
E356 Total	1994	532,104.00	7,343.00	148,359.00	(141,016.00)	-26.50%	-42.59%	-80.88%	-78.46%							
E356 Total	1995	1,483,725.00	0.00	199,246.00	(199,246.00)	-13.43%	-16.88%	-24.90%	-41.49%	-42.66%						
E356 Total	1996	200,223.00	6.00	258,821.00	(258,815.00)	-129.26%	-27.20%	-27.03%	-32.80%	-47.90%	-48.65%					
E356 Total	1997	84,062.00	0.00	161,438.00	(161,438.00)	-192.05%	-147.83%	-35.04%	-33.06%	-37.70%	-52.19%	-52.69%				
E356 Total	1998	200,822.00	0.00	335,680.00	(335,680.00)	-167.15%	-174.50%	-155.83%	-48.52%	-43.83%	-46.57%	-59.82%	-59.92%			
E356 Total	1999	966,160.92	0.00	787,321.33	(787,321.33)	-81.49%	-96.23%	-102.67%	-106.34%	-59.37%	-54.33%	-55.23%	-65.06%	-64.95%		
E356 Total	2000	308,809.00	0.00	1,049,111.34	(1,049,111.34)	-339.73%	-144.04%	-147.18%	-139.25%	-147.29%	-86.06%	-77.67%	-76.12%	-84.79%	-83.99%	
E356 Total	2001	1,340,342.00	0.00	1,877,240.03	(1,877,240.03)	-140.06%	-177.45%	-142.00%	-131.87%	-145.19%	-144.16%	-101.85%	-94.01%	-91.57%	-97.92%	
E356 Total	2002	1,154,357.07	557.05	648,294.50	(647,737.45)	-56.11%	-101.21%	-127.49%	-94.81%	-118.30%	-119.83%	-120.27%	-92.65%	-87.03%	-85.46%	
E356 Total	2003	496,330.09	0.00	802,270.12	(802,270.12)	-161.64%	-87.84%	-111.24%	-100.83%	-121.04%	-123.12%	-124.39%	-124.59%	-98.14%	-92.51%	
E356 Total	2004	1,638,423.59	0.00	966,798.60	(966,798.60)	-59.01%	-82.87%	-73.48%	-52.21%	-108.20%	-103.83%	-105.91%	-107.08%	-107.78%	-90.00%	
E356 Total	2005	491,180.60	0.00	833,998.37	(833,998.37)	-169.79%	-84.56%	-99.13%	-68.86%	-100.14%	-113.77%	-108.89%	-110.67%	-111.69%	-112.20%	
E356 Total	2006	1,065,253.00	321,097.00	164,721.00	156,376.00	14.68%	-43.54%	-51.47%	-44.55%	-63.86%	-80.37%	-92.70%	-91.25%	-93.24%	-94.31%	
E356 Total	2007	845,162.00	0.00	758,275.00	(758,275.00)	-89.72%	-31.51%	-59.79%	-35.54%	-70.65%	-67.70%	-81.49%	-92.36%	-91.10%	-92.89%	
E356 Total	2008	904,122.00	0.00	631,669.00	(631,669.00)	-69.87%	-79.46%	-43.83%	-37.32%	-61.37%	-70.52%	-68.00%	-80.17%	-89.89%	-89.01%	
E356 Total	2009	667,649.00	0.00	1,338,898.00	(1,338,898.00)	-200.54%	-125.37%	-112.91%	-78.37%	-85.73%	-77.93%	-84.73%	-80.18%	-89.51%	-98.18%	
E356 Total	2010	935,893.62	0.00	1,537,856.48	(1,537,856.48)	-164.32%	-179.40%	-139.91%	-104.64%	-93.03%	-100.71%	-90.28%	-95.31%	-89.79%	-96.85%	
E356 Total	2011	868,849.74	0.00	3,052,944.51	(3,052,944.51)	-351.38%	-254.37%	-239.84%	-175.62%	-173.38%	-135.49%	-138.41%	-120.87%	-123.42%	-114.85%	
E356 Total	2012	38,282.70	0.00	383,155.73	(383,155.73)	-1000.86%	-378.79%	-269.88%	-198.11%	-203.37%	-180.82%	-141.71%	-144.08%	-125.38%	-127.65%	
E356 Total	2013	307,764.84	0.00	303,727.47	(303,727.47)	-98.69%	-198.49%	-307.83%	-173.88%	-234.76%	-194.71%	-175.28%	-139.36%	-141.80%	-124.33%	
E356 Total	2014	1,139,700.09	0.00	2,765,179.22	(2,765,179.22)	-242.62%	-212.02%	-232.35%	-146.61%	-244.43%	-237.02%	-205.94%	-188.73%	-156.74%	-157.62%	
E356 Total	2015	168,069.62	0.00	2,632,117.53	(2,632,117.53)	-1566.09%	-412.71%	-352.89%	-344.72%	-362.20%	-308.65%	-291.16%	-251.39%	-228.13%	-190.86%	
E356 Total	2016	466,006.20	0.00	3,151,911.00	(3,151,911.00)	-676.37%	-912.20%	-481.98%	-410.72%	-435.70%	-411.19%	-352.32%	-330.25%	-287.42%	-261.07%	
E356 Total	2017	551,113.55	0.00	3,068,815.92	(3,068,815.92)	-556.84%	-611.60%	-746.96%	-380.79%	-452.84%	-460.70%	-433.86%	-377.50%	-354.53%	-311.97%	-208.54%
E357	1991	0.00	0.00	171.00	(171.00)	NA										

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Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
E357	1992	0.00	0.00	2,275.00	(2,275.00)	NA	NA									
E357	1993	0.00	0.00	861.00	(861.00)	NA	NA	NA								
E357	1994	4,568.00	0.00	353.00	(353.00)	-7.73%	-26.58%	-76.38%	-80.12%							
E357	1995	466.00	0.00	0.00	0.00	0.00%	-7.01%	-24.12%	-69.31%	-72.71%						
E357	1996	118,884.00	23,394.00	546.00	22,848.00	19.22%	19.14%	18.15%	17.46%	15.62%	15.48%					
E357	1997	0.00	0.00	0.00	0.00	NA	19.22%	19.14%	18.15%	17.46%	15.62%	15.48%				
E357	1998	12,055.00	0.00	0.00	0.00	0.00%	0.00%	17.45%	17.39%	16.54%	15.91%	14.24%	14.11%			
E357	1999	7,317.63	0.00	60,647.00	(60,647.00)	-828.78%	-313.06%	-313.06%	-27.34%	-27.25%	-26.63%	-27.23%	-28.81%	-28.93%		
E357	2000	1,790.00	0.00	29,084.61	(29,084.61)	-1624.84%	-985.24%	-424.01%	-424.01%	-47.76%	-47.60%	-46.34%	-46.94%	-48.51%	-48.62%	
E357	2001	54,063.00	0.00	6,894.84	(6,894.84)	-12.75%	-64.42%	-152.96%	-128.45%	-128.45%	-38.01%	-37.92%	-37.23%	-37.66%	-38.80%	
E357	2002	6,511.61	0.00	3,436.49	(3,436.49)	-52.77%	-17.06%	-63.20%	-56.57%	-122.42%	-122.42%	-38.49%	-38.40%	-37.72%	-38.14%	
E357	2003	57,788.39	0.00	8,671.30	(8,671.30)	-15.01%	-18.83%	-16.05%	-15.82%	-85.30%	-77.93%	-77.93%	-33.24%	-33.18%	-32.74%	
E357	2004	1,854.96	0.00	13,637.26	(13,637.26)	-735.18%	-37.40%	-38.92%	-21.42%	-50.59%	-94.62%	-86.55%	-86.55%	-38.24%	-38.17%	
E357	2005	14,900.91	0.00	23,019.08	(23,019.08)	-154.48%	-218.77%	-60.81%	-55.92%	-41.19%	-61.90%	-100.81%	-93.03%	-93.03%	-44.53%	
E357	2006	0.00	0.00	0.00	0.00	NA	-154.48%	-218.77%	-49.17%	-60.16%	-41.19%	-61.90%	-100.81%	-93.03%	-93.03%	
E357	2007	0.00	0.00	62.00	(62.00)	NA	NA	-154.90%	-137.75%	-60.89%	-60.24%	-41.24%	-61.94%	-100.85%	-93.07%	
E357	2008	341.00	0.00	178.00	(178.00)	-52.20%	-70.38%	-70.38%	-1.57%	-215.81%	-60.85%	-60.20%	-41.27%	-61.92%	-100.74%	
E357	2009	0.00	0.00	98.00	(98.00)	NA	-80.94%	-99.12%	-99.12%	-153.24%	-216.38%	-60.98%	-60.32%	-41.34%	-61.99%	
E357	2010	0.00	0.00	0.00	0.00	NA	NA	-80.94%	-80.94%	-99.12%	-153.24%	-216.38%	-60.98%	-60.32%	-41.34%	
E357	2011	0.00	0.00	0.00	0.00	NA	NA	NA	-28.74%	-99.12%	-99.12%	-153.24%	-216.38%	-60.98%	-60.32%	
E357	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	-80.94%	-99.12%	-99.12%	-153.24%	-216.38%	-60.98%	
E357	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	-80.94%	-99.12%	-99.12%	-153.24%	-216.38%	
E357	2014	0.00	0.00	(4,035.92)	4,035.92	NA	NA	NA	NA	NA	NA	1102.62%	1084.43%	1084.43%	-126.76%	
E357	2015	0.00	0.00	72,764.49	(72,764.49)	NA	NA	NA	NA	NA	NA	NA	-20235.94%	-20254.13%	-20254.13%	
E357	2016	0.00	0.00	157,298.99	(157,298.99)	NA	NA	NA	NA	NA	NA	NA	NA	-66364.68%	-66382.86%	
E357	2017	264.66	0.00	119,142.74	(119,142.74)	-45017.28%	-104451.65%	-131945.22%	-131945.22%	-130420.28%	-130420.28%	-130420.28%	-130420.28%	-130457.30%	-57036.34%	-520.07%
E358	1991	12,893.00	11,281.00	6,614.00	4,667.00	36.20%										
E358	1992	76,184.00	14,965.00	4,047.00	10,918.00	14.33%	17.50%									
E358	1993	43,156.00	7,456.00	1,975.00	5,481.00	12.70%	13.74%	15.93%								
E358	1994	73,275.00	0.00	12,111.00	(12,111.00)	-16.53%	-5.69%	2.23%	4.36%							
E358	1995	30,808.00	31,611.00	6,444.00	25,167.00	81.69%	12.54%	12.59%	13.18%	14.44%						
E358	1996	152,838.00	5,184.00	(72.00)	5,256.00	3.44%	16.57%	7.13%	7.93%	9.23%	10.12%					
E358	1997	88,429.00	0.00	182.00	(182.00)	-0.21%	2.10%	11.11%	5.25%	6.08%	7.43%	8.21%				
E358	1998	9,540.00	0.00	1,000.00	(1,000.00)	-10.48%	-1.21%	1.62%	10.38%	4.83%	5.68%	7.07%	7.84%			
E358	1999	1,457,662.72	0.00	38,376.00	(38,376.00)	-2.63%	-2.68%	-2.54%	-2.01%	-0.53%	-1.17%	-0.85%	-0.25%	-0.01%		
E358	2000	243,288.00	0.00	70,478.45	(70,478.45)	-28.97%	-6.40%	-6.42%	-6.11%	-5.37%	-4.02%	-4.46%	-4.11%	-3.46%	-3.23%	
E358	2001	1,156,103.00	0.00	62,148.70	(62,148.70)	-5.38%	-9.48%	-5.99%	-5.97%	-5.83%	-5.37%	-4.52%	-4.79%	-4.56%	-4.13%	
E358	2002	15,494.51	1,181.32	5,849.51	(4,668.19)	-30.13%	-5.70%	-9.70%	-4.78%	-6.13%	-5.95%	-5.49%	-4.64%	-4.91%	-4.68%	
E358	2003	212,609.04	0.00	16,228.83	(16,228.83)	-7.63%	-9.16%	-6.00%	-5.10%	-6.22%	-6.23%	-6.07%	-5.63%	-4.83%	-5.08%	
E358	2004	32,577.02	0.00	44,781.52	(44,781.52)	-137.46%	-24.88%	-25.20%	-4.64%	-11.95%	-7.59%	-7.60%	-7.40%	-6.91%	-6.10%	
E358	2005	272,916.94	0.00	130,564.32	(130,564.32)	-47.84%	-57.40%	-36.98%	-35.90%	-15.29%	-17.01%	-10.83%	-10.83%	-10.56%	-9.97%	
E358	2006	5,524.00	0.00	332.00	(332.00)	-6.01%	-47.01%	-56.48%	-33.55%	-36.46%	-15.26%	-16.98%	-10.82%	-10.82%	-10.55%	
E358	2007	0.00	0.00	447.00	(447.00)	NA	-14.10%	-47.17%	-42.23%	-36.73%	-36.54%	-15.29%	-17.01%	-10.84%	-10.84%	
E358	2008	31,682.00	0.00	10,794.00	(10,794.00)	-34.07%	-35.48%	-31.11%	-3.73%	-54.54%	-36.58%	-36.41%	-15.63%	-17.28%	-11.05%	
E358	2009	0.00	0.00	7,613.00	(7,613.00)	NA	-58.10%	-59.51%	-50.67%	-48.29%	-56.76%	-37.95%	-37.74%	-16.07%	-17.67%	
E358	2010	0.00	0.00	0.00	0.00	NA	NA	-58.10%	-58.10%	-51.57%	-48.29%	-56.76%	-37.95%	-37.74%	-16.07%	
E358	2011	0.00	0.00	0.00	0.00	NA	NA	NA	-24.03%	-59.51%	-51.57%	-48.29%	-56.76%	-37.95%	-37.74%	
E358	2012	993,909.00	2,208.00	420,412.93	(418,204.93)	-42.08%	-42.08%	-42.08%	-42.08%	-42.57%	-42.62%	-42.42%	-43.55%	-45.84%	-40.60%	
E358	2013	297,767.65	0.00	331,670.99	(331,670.99)	-111.39%	-58.05%	-58.05%	-58.05%	-58.64%	-58.06%	-58.09%	-57.87%	-56.16%	-57.78%	
E358	2014	0.00	0.00	103,677.54	(103,677.54)	NA	-146.20%	-66.08%	-66.08%	-66.08%	-66.67%	-65.89%	-65.92%	-65.67%	-62.64%	
E358	2015	465,315.62	0.00	363,052.97	(363,052.97)	-78.02%	-100.30%	-104.63%	-45.44%	-69.24%	-69.24%	-69.68%	-69.05%	-69.07%	-68.88%	
E358	2016	0.00	0.00	634,917.64	(634,917.64)	NA	-214.47%	-236.75%	-144.37%	-105.38%	-105.38%	-105.38%	-105.81%	-104.54%	-104.57%	
E358	2017	169,277.59	0.00	174,044.85	(174,044.85)	-102.82%	-477.89%	-184.69%	-184.69%	-172.40%	-105.15%	-105.15%	-105.15%	-105.55%	-104.39%	-90.12%
359.1	1991	0.00	0.00	0.00	0.00	NA										
359.1	1992	0.00	0.00	6,522.00	(6,522.00)	NA	NA									
359.1	1993	0.00	0.00	350.00	(350.00)	NA	NA	NA								
359.1	1994	0.00	0.00	7,148.00	(7,148.00)	NA	NA	NA	NA							

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359.1	1995	0.00	0.00	597.00	(597.00)	NA	NA	NA	NA	NA						
359.1	1996	3,770.00	0.00	92.00	(92.00)	-2.44%	-18.28%	-207.88%	-217.16%	-390.16%	-390.16%					
359.1	1997	0.00	0.00	338.00	(338.00)	NA	-11.41%	-27.24%	-216.84%	-226.13%	-399.12%	-399.12%				
359.1	1998	0.00	0.00	974.00	(974.00)	NA	NA	-37.24%	-53.08%	-242.68%	-251.96%	-424.96%	-424.96%			
359.1	1999	0.00	0.00	7,499.00	(7,499.00)	NA	NA	NA	-236.15%	-251.99%	-441.59%	-450.88%	-623.87%	-623.87%		
359.1	2000	0.00	0.00	7,463.58	(7,463.58)	NA	NA	NA	NA	-434.13%	-449.96%	-639.56%	-648.85%	-821.85%	-821.85%	
359.1	2001	0.00	0.00	4,319.14	(4,319.14)	NA	NA	NA	NA	NA	-548.69%	-564.53%	-754.13%	-763.41%	-936.41%	
359.1	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-548.69%	-564.53%	-754.13%	-763.41%	
359.1	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	-548.69%	-564.53%	-754.13%	
359.1	2004	0.00	0.00	2,803.70	(2,803.70)	NA	NA	NA	NA	NA	NA	NA	NA	-623.06%	-638.90%	
359.1	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	-623.06%	
359.1	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2014	0.00	0.00	119,591.86	(119,591.86)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2015	0.00	0.00	290,352.94	(290,352.94)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2016	0.00	0.00	109,891.25	(109,891.25)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.1	2017	0.00	0.00	149,106.77	(149,106.77)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	1991	0.00	0.00	0.00	0.00	NA										
359.2	1992	0.00	0.00	0.00	0.00	NA	NA									
359.2	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
359.2	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
359.2	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
359.2	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
359.2	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				
359.2	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
359.2	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
359.2	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2015	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2016	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.2	2017	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	1991	0.00	0.00	0.00	0.00	NA										
359.6	1992	0.00	0.00	0.00	0.00	NA	NA									
359.6	1993	0.00	0.00	0.00	0.00	NA	NA	NA								
359.6	1994	0.00	0.00	0.00	0.00	NA	NA	NA	NA							
359.6	1995	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA						
359.6	1996	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA					
359.6	1997	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA				

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Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
359.6	1998	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA			
359.6	1999	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA		
359.6	2000	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2001	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2004	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2014	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2015	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2016	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
359.6	2017	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	1991	0.00	0.00	0.00	0.00	NA										
E359	1992	0.00	0.00	6,522.00	(6,522.00)	NA	NA									
E359	1993	0.00	0.00	350.00	(350.00)	NA	NA	NA								
E359	1994	0.00	0.00	7,148.00	(7,148.00)	NA	NA	NA	NA							
E359	1995	0.00	0.00	597.00	(597.00)	NA	NA	NA	NA	NA						
E359	1996	3,770.00	0.00	92.00	(92.00)	-2.44%	-18.28%	-207.88%	-217.16%	-390.16%	-390.16%					
E359	1997	0.00	0.00	338.00	(338.00)	NA	-11.41%	-27.24%	-216.84%	-226.13%	-399.12%	-399.12%				
E359	1998	0.00	0.00	974.00	(974.00)	NA	NA	-37.24%	-53.08%	-242.68%	-251.96%	-424.96%	-424.96%			
E359	1999	0.00	0.00	7,499.00	(7,499.00)	NA	NA	NA	-236.15%	-251.99%	-441.59%	-450.88%	-623.87%	-623.87%		
E359	2000	0.00	0.00	7,463.58	(7,463.58)	NA	NA	NA	NA	-434.13%	-449.96%	-639.56%	-648.85%	-821.85%	-821.85%	
E359	2001	0.00	0.00	4,319.14	(4,319.14)	NA	NA	NA	NA	NA	-548.69%	-564.53%	-754.13%	-763.41%	-936.41%	
E359	2002	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	-548.69%	-564.53%	-754.13%	-763.41%	
E359	2003	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	-548.69%	-564.53%	-754.13%	
E359	2004	0.00	0.00	2,803.70	(2,803.70)	NA	NA	NA	NA	NA	NA	NA	NA	-623.06%	-638.90%	
E359	2005	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	-623.06%	
E359	2006	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2007	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2008	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2009	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2010	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2011	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2012	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2013	0.00	0.00	0.00	0.00	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2014	0.00	0.00	119,591.86	(119,591.86)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2015	0.00	0.00	290,352.94	(290,352.94)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2016	0.00	0.00	109,891.25	(109,891.25)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E359	2017	0.00	0.00	149,106.77	(149,106.77)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	
E352-E359	1991	2,279,601.00	132,667.00	628,302.00	(495,635.00)	-21.74%	-21.74%									
E352-E359	1992	584,751.00	119,733.00	878,602.00	(758,869.00)	-129.78%	-43.80%	-43.80%								
E352-E359	1993	1,513,570.00	165,692.00	728,329.00	(562,637.00)	-37.17%	-62.98%	-41.51%	-41.51%							
E352-E359	1994	1,335,188.00	88,617.00	387,468.00	(298,851.00)	-22.38%	-30.24%	-47.19%	-37.04%	-37.04%						
E352-E359	1995	2,847,125.71	237,614.00	367,003.00	(129,389.00)	-4.54%	-10.24%	-17.40%	-27.86%	-26.23%	-26.23%					
E352-E359	1996	778,819.00	29,442.00	573,367.50	(543,925.50)	-69.84%	-18.57%	-19.60%	-23.70%	-32.49%	-29.87%	-29.87%				
E352-E359	1997	546,864.99	103,115.38	469,284.14	(366,168.76)	-66.96%	-68.65%	-24.91%	-24.30%	-27.07%	-34.97%	-31.92%	-31.92%			
E352-E359	1998	843,993.73	0.00	651,757.01	(651,757.01)	-77.22%	-73.19%	-71.99%	-33.71%	-31.33%	-32.45%	-39.19%	-35.48%	-35.48%		
E352-E359	1999	4,250,671.13	0.00	1,688,051.55	(1,688,051.55)	-39.71%	-45.93%	-47.97%	-42.15%	-36.46%	-34.69%	-35.00%	-39.36%	-36.68%	-36.68%	
E352-E359	2000	1,544,295.00	130,150.72	2,798,482.76	(2,668,332.04)	-172.79%	-75.18%	-75.44%	-69.69%	-74.31%	-55.94%	-52.25%	-50.58%	-53.83%	-49.40%	

SAN DIEGO GAS AND ELECTRIC T05
RETIREMENT AND NET SALVAGE
AS ADJUSTED
DATA THROUGH DECEMBER 2017

Account	Year	Adjusted Ret	Adjusted Salvage	Adjusted Removal Cost	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %	15- yr Net Salv. %
E352-E359	2001	3,670,776.14	0.00	2,760,832.42	(2,760,832.42)	-75.21%	-104.11%	-75.19%	-69.03%	-74.93%	-74.59%	-60.82%	-57.58%	-55.79%	-58.21%	
E352-E359	2002	3,931,277.62	42,342.98	3,244,874.37	(3,202,531.39)	-81.46%	-78.44%	-94.37%	-64.43%	-77.04%	-76.67%	-76.33%	-65.23%	-62.33%	-60.54%	
E352-E359	2003	3,106,512.18	20,005.08	3,061,544.89	(3,041,539.81)	-97.91%	-88.72%	-84.09%	-73.49%	-80.96%	-80.78%	-80.36%	-79.92%	-69.95%	-67.17%	
E352-E359	2004	6,432,399.54	750.00	3,394,712.87	(3,393,962.87)	-52.76%	-67.47%	-71.55%	-56.23%	-80.64%	-73.05%	-73.20%	-73.06%	-72.96%	-65.99%	
E352-E359	2005	6,422,320.96	0.00	4,512,229.52	(4,512,229.52)	-70.26%	-61.50%	-68.59%	-55.03%	-71.77%	-77.98%	-72.44%	-72.57%	-72.47%	-72.41%	
E352-E359	2006	9,793,181.00	360,411.00	2,757,009.00	(2,396,598.00)	-24.47%	-42.61%	-45.49%	-40.00%	-55.74%	-57.88%	-62.97%	-60.44%	-60.80%	-60.88%	
E352-E359	2007	8,763,776.00	0.00	3,350,865.00	(3,350,865.00)	-38.24%	-30.97%	-41.07%	-32.66%	-48.37%	-51.75%	-53.79%	-58.00%	-56.38%	-56.74%	
E352-E359	2008	5,047,658.00	0.00	6,080,838.00	(6,080,838.00)	-120.47%	-68.29%	-50.11%	-39.39%	-54.13%	-57.56%	-59.72%	-60.93%	-64.48%	-62.49%	
E352-E359	2009	6,009,999.13	1,066.00	12,433,858.00	(12,432,792.00)	-206.87%	-167.43%	-110.31%	-73.83%	-79.84%	-75.74%	-77.25%	-77.59%	-77.42%	-80.11%	
E352-E359	2010	8,762,298.76	(1,062.00)	9,632,554.82	(9,633,616.82)	-109.94%	-149.38%	-142.01%	-98.47%	-88.32%	-85.73%	-81.59%	-82.52%	-82.45%	-82.02%	
E352-E359	2011	5,608,148.18	22,800.00	15,047,901.79	(15,025,101.79)	-267.92%	-171.59%	-182.00%	-145.87%	-136.07%	-111.22%	-106.00%	-99.98%	-99.87%	-98.74%	
E352-E359	2012	5,223,449.90	6,200.80	6,971,166.19	(6,964,965.39)	-133.34%	-203.02%	-161.40%	-123.51%	-163.57%	-135.70%	-113.57%	-108.57%	-102.78%	-102.55%	
E352-E359	2013	9,292,851.09	151,500.00	7,160,440.54	(7,008,940.54)	-75.42%	-96.26%	-144.10%	-100.39%	-146.33%	-143.06%	-124.20%	-107.51%	-103.82%	-99.22%	
E352-E359	2014	10,915,870.17	0.00	9,220,806.07	(9,220,806.07)	-84.47%	-80.31%	-91.20%	-74.72%	-120.23%	-131.59%	-130.49%	-116.93%	-103.89%	-101.04%	
E352-E359	2015	7,125,545.85	0.00	9,907,890.52	(9,907,890.52)	-139.05%	-106.03%	-95.62%	-80.28%	-126.10%	-123.08%	-132.60%	-131.54%	-119.29%	-107.16%	
E352-E359	2016	13,601,253.37	0.00	15,028,340.10	(15,028,340.10)	-110.49%	-120.31%	-107.95%	-83.44%	-104.27%	-122.00%	-120.26%	-128.08%	-127.54%	-117.80%	
E352-E359	2017	5,816,261.65	0.00	14,535,943.97	(14,535,943.97)	-249.92%	-152.26%	-148.71%	-129.99%	-119.14%	-120.57%	-134.92%	-131.62%	-137.87%	-136.74%	

Exhibit No. SD-0017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER19-__-000

PREPARED DIRECT TESTIMONY OF

JOEL DUMAS

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

October 30, 2018

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PREPARED DIRECT TESTIMONY OF
JOEL DUMAS
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Joel Dumas. My position is Director of Corporate Tax at Sempra Energy, the parent company of San Diego Gas & Electric Company ("SDG&E"). My business address is 488 8th Avenue, San Diego, CA 92101.

Q. Please describe your current responsibilities.

A. I am currently responsible for federal and state income taxes and regulatory tax matters for Sempra Energy's regulated public utilities, as well as other nonregulated U.S. infrastructure and U.S. renewable businesses.

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Science degree in Geology from Texas Tech University and a Master of Science in Accounting, with tax emphasis, from Texas Tech University. Prior to my current position, I was Chief Tax Strategist for Sempra Energy responsible for a wide range of consolidated income tax responsibilities including tax policy and planning. Prior to my employment at Sempra, I was Senior Manager of International Tax for Devon Energy where my duties included foreign country tax reporting and compliance as well as the related U.S. tax consequences of those international operations. Prior to that I was Global Tax Planning Manager for Unocal Corporation with duties encompassing multijurisdictional tax issues. During my tenure at Unocal I was also responsible for the tax reporting and compliance for all the U.S. oil and gas operations, including the Gulf of

Mexico. In addition to my industry experience I was in public accounting with most recent responsibilities as a senior manager at one of the "Big Eight" firms.

Q. Have you previously submitted testimony to this Commission?

A. No.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony and how is it organized?

A. The purpose of my testimony is to explain certain tax issues related to SDG&E's TO5 filing. In Section III, I discuss an error pertaining to SDG&E's calculation of the Tax Net Operating Loss ("TNOL") related to its FERC-jurisdictional transmission business, which SDG&E plans to correct for ratemaking purposes through the TO5 Formula, as further discussed by SDG&E witness Alana Hammer. While Ms. Hammer explains the ratemaking aspects error correction, I explain it from a tax accounting perspective.

In Section IV, I discuss the impact of the Tax Cuts and Jobs Act ("TCJA") on SDG&E, including the change in the federal income tax rate and the treatment of excess deferred taxes. Ms. Hammer explains the rate impact of the federal income tax rate change under the TCJA.

In Section V, I discuss certain changes SDG&E proposes to make to certain tax-related terminology in Appendix VIII of the Transmission Owner tariff, compared to the terminology in the existing tariff.

III. ACCUMULATED DEFERRED INCOME TAX (ADIT) ERROR CORRECTION FOR FERC ASSETS

Q. Please provide an overview of SDG&E's ADIT error for FERC assets.

A. I explain ADIT and related tax accounting concepts in further detail below, but in general, ADIT is an adjustment to rate base in the computation of a utility's revenue requirement. ADIT includes both deferred tax liabilities ("DTL"), as well as deferred tax assets ("DTA"). An example of a DTL would be a 100% tax bonus depreciation expense claimed in the first year of an asset's service life with the corresponding book depreciation expense occurring over twenty years. An example of a DTA would be a book actuarial expense accrual for a pension liability with the tax return deduction not occurring until the pension obligation is funded, whereas the book expense is recorded prior to funding.

Since 2011, SDG&E has incorrectly calculated the FERC TNOL, which is a DTA component of ADIT. Specifically, rather than calculating TNOL using a stand-alone methodology based on a jurisdictional distinction between FERC and California Public Utilities Commission ("CPUC") assets or businesses, SDG&E incorrectly included CPUC taxable income in the computation of its FERC TNOL. SDG&E's then reflected this incorrect FERC TNOL in ADIT, which is used in the calculation of SDG&E's FERC revenue requirement. This had the effect of prematurely reducing (and ultimately wiping out) the TNOL carryforward SDG&E experienced in its FERC transmission business.

ADIT is recorded in Accounts 190-Accumulated Deferred Income Taxes Debit (or DTA), 282-Accumulated Deferred Income Taxes Other Property and 283-Accumulated Deferred Income Taxes Other. While SDG&E did not make any errors in the total ADIT recorded in its FERC Form 1 reports, it did err in the way it calculated the DTA on Schedule Page 274 of its FERC Form 1 reports for the years 2012-2016.[1] Specifically, after conducting a review of its TNOL calculation, SDG&E realized that it erroneously computed the TNOL, or DTA, for FERC book and ratemaking purposes using both FERC-jurisdictional and CPUC-jurisdictional income and expense. SDG&E should have only used FERC-jurisdictional amounts in computing the TNOL, or DTA. If SDG&E had done the computation correctly, there would have been a TNOL carryforward, generated primarily from the 100% bonus depreciation SDG&E claimed[2] in connection with the Sunrise Powerlink transmission facility in 2012.[3] In addition, SDG&E claimed 50% bonus depreciation on other electric transmission projects that went into service in 2013-17. If SDG&E had correctly computed the DTA amounts by including only FERC-jurisdictional transmission related amounts, SDG&E would have a TNOL carryforward through at least 2020. Ultimately, this error eliminated SDG&E's FERC-jurisdictional TNOL carryforward as of 2015 year-end FERC reporting. In Exhibit No. SD-0018, I show the SDG&E FERC-jurisdictional taxable income and losses by year, resulting in the corrected FERC TNOL, or DTA. In summary, 100% tax bonus depreciation from FERC transmission assets generated SDG&E's FERC DTL and offsetting FERC TNOL, or DTA, all of which should exclude CPUC income.

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1 In 2018, SDG&E corrected this error in its FERC Form 1 reports for 2012-2016. It has also reflected the correction in its FERC Form 1 report for 2017.

2 *See* Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, Pub. L. 11-312, 124 Stat. 3296 (Dec. 17, 2010). Bonus depreciation allows a taxpayer to further accelerate the depreciation of certain assets for tax purposes by taking additional first year depreciation on qualified property. It represents a tax incentive the federal government provides to taxpayers to encourage investment.

3 The Sunrise Powerlink is a 117 mile, $1.887 billion 500-kilovolt electric transmission line that runs from Imperial County to San Diego.

Q. What is the magnitude of SDG&E's ADIT error?

A. In Table 1 below, I have indicated the magnitude of the error by year.

Table 1: SDG&E's ADIT Error

($ in thousands)

	As Filed in TO4 Formula[4]			**Correction**		
Year	Deferred Tax Liability	Deferred Tax Asset	Total Transmission-Related ADIT	Deferred Tax Liability	Deferred Tax Asset	Total Transmission-Related ADIT
2012	$(641,099)	$366,831	**$(274,269)**	$(641,099)	$422,295	**$(218,804)**
2013	$(733,597)	$316,542	**$(417,055)**	$(733,597)	$374,388	**$(359,209)**
2014	$(838,075)	$225,285	**$(612,790)**	$(838,075)	$373,951	**$(464,125)**
2015	$(878,415)	$-	**$(878,415)**	$(878,415)	$334,787	**$(543,628)**
2016	$(931,658)	$-	**$(931,658)**	$(931,658)	$287,918	**$(643,740)**
	TO5 Formula[5]					
2017	$(1,028,062)	$-[6]	**$(794,243)**	$(1,028,062)	$270,712	**$(757,350)** [7]

As shown in Table 1, SDG&E's computation of its DTL in each year remains unchanged; the error pertains solely to the computation of the DTA. The magnitude of the error each year can be seen in comparing the two columns labeled "Total Transmission-Related ADIT." Ms. Hammer discusses the ratemaking impact of the ADIT error.

Q. Please describe ADIT in greater detail, including how it arises.

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4 The "As Filed in TO4 Formula" amounts are reflected in the Footnotes on page 450.1 for Schedule 274 of SDG&E's FERC Form 1.

5 The "TO5 Formula" amounts reflect the amounts in the base period for TO5 Cycle 1, excluding other deferred taxes related to non-property balances, that are expected to be filed with FERC in October 2018.

6 In 2017, a Deferred Tax Asset amount of $233,819,000 for the NOL computed under the new standalone methodology was reflected in the footnotes to FERC Form 1, on page 450.1 for Schedule 234.

7 These represent the cumulative balances, net of the Citizens Sunrise Transmission LLC amounts, as of December 31 of each year shown. An average of the beginning of the year and end of the year balance is used to compute the revenue requirement for each period.

A. ADIT represents temporary differences in the recognition of income and expenses between ratemaking income tax expense and income taxes paid to the Internal Revenue Service ("IRS"). For ratemaking purposes, utilities compute income taxes based on the return on net rate base calculated using straight line depreciation. But for tax purposes, utilities typically compute income taxes due to the IRS using accelerated depreciation. Use of accelerated depreciation lowers the utility's income taxes in early years, followed by an increase of taxes in later years. This difference also creates a difference between income taxes owed to the IRS and income taxes included in FERC rates. The foregoing would result in a DTL being recorded to the proper ADIT account.

A DTL provides the utility with cost-free capital, sometimes referred to as a "tax free" loan, which represents an investment opportunity for the utility. Thus, the Commission requires that it be deducted from rate base, so that the utility does not earn a return on that cost-free capital. This deduction is reduced over time as the relationship between income taxes paid and income taxes collected in rates reverses. This method of passing the benefits of accelerated depreciation to ratepayers is referred to as tax normalization.[8]

As discussed, the opposite of a DTL is a DTA – which generally causes an increase to rate base. One specific type of DTA is a TNOL, which represents expenses exceeding revenues for income tax purposes. This "excess" can only be refunded by a carryforward (or a carryback) to future tax years. Since no cash

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8 *See Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs*, 164 FERC ¶ 61,030 at P 11 (2018).

benefit has occurred, by virtue of the "excess," the "interest free loan" from the government, or DTL, must be reduced accordingly by the TNOL or DTA, carried forward to future years. Under income tax regulations, a TNOL arises when deductions taken on corporate income tax return exceed taxable income for a given year, in which case the utility applies the TNOL against net taxable income for the year. If any TNOL remains, the utility may use it to offset taxable income in future years. For tax purposes, a TNOL can offset a utility's net taxable income the previous two years (referred to as a "carryback"), or it can be applied prospectively to offset taxable income for the following 20 years (referred to as a "carryforward").[9]

Q. Has SDG&E notified interested parties of this error?

A. Yes. SDG&E alerted interested parties to the ADIT error in letter submitted with a preview of its TO5 Formula filing on May 31, 2018. SDG&E has convened Technical Conferences with interested parties since that preview, and I have personally explained the error at length in those conferences.

Q. From a tax accounting perspective, why do you believe it is necessary to correct SDG&E's ADIT error?

A. Since the issuance of Order No. 144 in 1981, the FERC's regulations have required companies to determine the income tax allowance included in jurisdictional rate levels on a fully normalized basis. As the Commission has recognized, the purpose of ADIT and normalization is to ensure the matching of

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[9] Pursuant to the Tax Cuts and Jobs Act described generally in Section IV, the TNOL carryback and carryforward rules described herein only apply to TNOLs arising in tax years beginning before January 1, 2018.

the utility's income tax expense in rates with the tax effects of those same expenses.[10] If SDG&E's error is not corrected, that matching will not occur. That benefit is the TNOL carryforward which should be used to provide a future tax benefit to offset future tax profits from SDG&E's investments. In other words, the income tax calculation should follow the benefits and burdens of the underlying capital investment and revenue and expenses related to FERC-jurisdictional tariff on a standalone basis. Correcting the error will put SDG&E in compliance with depreciation normalization rules of the Internal Revenue Code (the "IRC"), thereby continuing the availability of accelerated tax depreciation to the benefit of its customers via the cost-free loan discussed in the previous question.

Q. Upon correcting the error, will there be an impact to SDG&E's CPUC-jurisdictional business?

A. Yes. Upon receiving FERC approval to correct the ADIT error on the FERC side, my understanding is that SDG&E plans to make a corresponding adjustment on the CPUC side.

IV. IMPACT OF TAX CUTS AND JOBS ACT

Q. Please describe the changes resulting from the TCJA.

A. On December 22, 2017, President Trump signed into law the TCJA,[11] which made a number of changes to the federal tax system, as the Commission recognized in its *Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on*

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[10] 164 FERC ¶ 61,030 at P 14.

[11] Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2054 (2017).

Commission-Jurisdictional Rates.[12] A significant change created by this legislation was the reduction of the federal corporate income tax rate from a maximum 35 percent to a flat 21 percent rate, effective January 1, 2018.[13]

Q. Have SDG&E's income taxes payable to the IRS changed because of the TCJA?

A. Yes. The reduced statutory corporate income tax rate will reduce the cost of service tax expense beginning January 1, 2018.

In addition, the net ADIT, as of December 31, 2017, including TNOLs, must be remeasured at the new 21 percent federal corporate tax rate. This remeasurement of ADIT resulted in excess deferred income taxes that had been collected from ratepayers at the higher rate (the "excess tax reserve").

Q. How does the TCJA define the "excess tax reserve"?

A. The TCJA defines the "excess tax reserve" as "(i) the reserve for deferred taxes (as described in section 168(i)(9)(A)(ii) of the Internal Revenue Code of 1986) as of the day before the corporate rate reductions…made by this section take effect, over (ii) the amount which would be the balance in such reserve if the amount of such reserve were determined by assuming that the corporate rate reductions provided in this Act were in effect for all prior periods."[14]

Q. Will SDG&E refund the excess tax reserve to ratepayers?

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[12] *Notice of Inquiry, Inquiry Regarding the Effect of Tax Cuts and Jobs Act on Commission-Jurisdictional Rates*, 162 FERC ¶ 61,233 (2018).

[13] *See* Section 13001 of the Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 stat. 2054 (2017).

[14] TCJA Section 13001(d)(3). The TCJA's reference to IRC Section 168(i)(9)(A)(ii) is to the IRS normalization rules.

A. Yes. SDG&E will refund the excess deferred taxes to its ratepayers. But in doing so, SDG&E must adhere to the timing rules and other requirements under the TCJA. Failure to follow these rules and procedures may result in a normalization violation.[15]

Q. Are there any specific categories of the excess tax reserves that are subject to the TCJA normalization rules?

A. Yes. Excess ADIT associated with utility plant assets (excess plant-based ADIT) are subject to the TCJA normalization rules. Utilities are not permitted to return the excess ADIT associated with utility plant assets more rapidly than ratably over the life of the underlying assets.[16]

Q. What is an acceptable method under the TCJA normalization rules to return the excess ADIT associated with utility plant assets?

A. The TCJA allows the average rate assumption method ("ARAM"), which requires amortization of the excess tax reserve over the remaining regulatory lives of the property that gave rise to the ADIT. If a utility's books and records do not contain the vintage data necessary to apply ARAM, the TCJA allows the utility to use an alternative method that amortizes the excess plant-based ADIT ratably over the remaining average life of composite rate used to compute depreciation for regulatory purposes.

The TCJA defines ARAM as follows:

> The average rate assumption method is the method under which the excess in the reserve for deferred taxes is

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15 TCJA Section 13001(d)(4).

16 TCJA Section 13001(d)(1).

> reduced over the remaining lives of the property as used in its regulated books of account which gave rise to the reserve for deferred taxes. Under such method, during the time period in which the timing differences for the property reverse, the amount of the adjustments to the reserve for the deferred taxes is calculated by multiplying – (i) the ratio of the aggregate deferred taxes for the property as of the beginning of the period in question, by (ii) the amount of the timing differences which reverse during such period.

During SDG&E's pre-filing Technical Conferences with interested parties, the individual components of the excess tax reserves were discussed and whether each component's refund methodology was "protected" under the ARAM normalization method.

Q. If a specific category of excess tax reserve is not subject to the IRC normalization rules, then what method should be used to refund it to ratepayers?

A. The requirement to use ARAM applies only to excess deferred taxes on plant-based assets that are subject to the IRS normalization rules. Other categories of excess tax reserve not subject to IRS normalization rules will be refunded to ratepayers as agreed with FERC. Although ARAM is not required, SDG&E proposes that an ARAM methodology should also be used to return these benefits to its ratepayers.

Q. Are you testifying about the ratemaking impacts of the change to SDG&E's income tax rate?

A. No. Ms. Hammer discusses that in her testimony.

V. CHANGES TO TERMINOLOGY IN APPENDIX VIII OF SDG&E'S TRANSMISSION OWNER TARIFF

Q. Why is SDG&E proposing to change certain tax-related terms in Appendix VIII of its Transmission Owner tariff?

A. Starting with the TO5 Formula, to better reflect all deferred taxes related to electric transmission property, SDG&E is now including FERC account 190 Deferred Tax Assets for Compensation Related items and Post-Retirement Benefits, and account 283 Deferred Tax Liabilities for Ad Valorem Taxes in Appendix VIII.

VERIFICATION

Joel Dumas hereby declares under penalty of perjury of the laws of the United States that the foregoing document is true and correct to the best of his knowledge and belief. See 28 U.S.C. § 1746.

Executed this 30th day of October, 2018

EXHIBIT NO. SD-0018

TO THE PREPARED DIRECT TESTIMONY OF

JOEL DUMAS

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

San Diego Gas & Electric
FERC Transmission - Taxable Income / (Loss) - Calculated on a Standalone or Ringfenced Basis
(In 1,000's)

	Federal IRS Audits Completed				IRS Years Still Subject to Audit				
	SAP and Other Systems		*PowerTax Fixed Asset System Implemented*						
	TO-3 Formula Rate		**TO-4 Formula Rate - Cycles 1-5**						
	Taxable Income / (Loss)								
	Actual								**Forecast**
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Tax Law Bonus Deprec %	*50%*	*50%/100%*	*50%/100%*	*50%/100% LPPP*	*50%*	*50%*	*50%*	*50%*	
Annual FERC PTBI Excluding AFUDC	107,881	113,287	116,008	213,550	282,620	270,261	309,570	313,896	322,241
Tax Adjustments:									
Ad Valorem Taxes - Book (Net of CWIP Cap)	-	-	85	8,316	18,956	21,659	25,406	28,724	30,867
Ad Valorem Taxes - Tax (Net of CWIP Cap)	-	-	(768)	(12,403)	(20,893)	(24,264)	(26,022)	(30,922)	(35,129)
Repairs	(2,849)	(2,590)	(27,325)	(27,425)	(40,251)	(32,993)	(24,443)	(39,671)	(28,191)
Repairs - §481 Adjustment			(93,069)						
Add back: Book Depreciation	39,162	42,183	45,805	64,819	80,943	92,512	96,950	102,580	110,427
Deduct: Tax Depreciation	(119,996)	(94,424)	(144,427)	(1,459,902)	(162,334)	(314,399)	(259,055)	(218,774)	(333,987)
Removal Costs	(9,947)	(7,706)	(15,048)	(6,971)	(7,160)	(9,221)	(9,908)	(15,028)	(14,536)
Taxable Income / (Loss)	14,251	50,750	(118,738)	(1,220,016)	151,881	3,556	112,498	140,805	51,692
Utilization of NOL - **Note 1**	(14,251)	(50,750)	-	-	(151,881)	(3,556)	(112,498)	(140,805)	(51,692)
Remaining NOL Balance	-	-	(53,737)	(1,273,754)	(1,121,873)	(1,118,317)	(1,005,818)	(865,014)	(813,322)
Federal Statutory Tax Rate	35%	35%	35%	35%	35%	35%	35%	35%	35%
Deferred Tax Asset - Note 2	**-**	**-**	**18,808**	**445,814**	**392,655**	**391,411**	**352,036**	**302,755**	**284,663**

Note 1: Tax years 2009 and 2010 have been included in the schedule to show the impact of a hypothetical 2-year carryback of the 2011 NOL on transmission property to be utilized against transmission taxable income in those years.
Note 2: Since Citizen's property is included in SDG&E's tax depreciation, the amounts above include Citizens. The deferred taxes related to Citizens are excluded when computing the revenue requirement.

Exhibit No. SD-0019

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER19-__-000

PREPARED DIRECT TESTIMONY OF

DR. ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

October 30, 2018

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PREPARED DIRECT TESTIMONY OF
DR. ROGER A. MORIN
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government. I am testifying on behalf of San Diego Gas & Electric Company ("SDG&E" or "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, The Management Exchange Inc., Exnet, Inc., and currently of S&P Global Intelligence (formerly SNL Center for Financial Education), where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last 30 years, I have conducted numerous national seminars on “Utility Finance,” “Utility Cost of Capital,” “Alternative Regulatory Frameworks,” and “Utility Capital Allocation,” which I have developed on behalf of aforementioned organizations.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including *The Journal of Finance*, *The Journal of Business Administration*, *International Management Review*, and *Public Utilities Fortnightly*. I published a widely-used treatise on regulatory finance, *Utilities' Cost of Capital*, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released my book, *Regulatory Finance*, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, *The New Regulatory Finance*, was published in 2006. I have been engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. Exhibit No. SD-0020 describes my professional credentials in more detail.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North America including the Federal Energy Regulatory Commission (“FERC”) and the California Public Utility Commission ("CPUC"). I have testified before the following state, provincial, and other local regulatory commissions:

Alabama	Florida	Missouri	Ontario
Alaska	Georgia	Montana	Oregon
Alberta	Hawaii	Nevada	Pennsylvania
Arizona	Illinois	New Brunswick	Quebec
Arkansas	Indiana	New Hampshire	South Carolina
British Columbia	Iowa	New Jersey	South Dakota
California	Kentucky	New Mexico	Tennessee
City of New Orleans	Louisiana	New York	Texas
Colorado	Maine	Newfoundland	Utah
CRTC	Manitoba	North Carolina	Vermont
Delaware	Maryland	North Dakota	Virginia
District of Columbia	Michigan	Nova Scotia	Wisconsin
FCC	Minnesota	Ohio	West Virginia
FERC	Mississippi	Oklahoma	Nebraska

The details of my participation in regulatory proceedings are provided in Exhibit No. SD-0020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to recommend a return on common equity ("ROE") for the jurisdictional electric transmission operations of SDG&E. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to ratepayers, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, (4) be comparable to returns offered on comparable risk investments, and (5) be consistent with the Commission's policy objectives. I will testify in this proceeding as to that opinion.

Q. PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDICES ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my testimony Exhibit Nos. SD-0020 through SD-27, and Appendices A and B. These exhibits and appendices relate directly to points in my testimony and are described in further detail in connection with the discussion of those points in my testimony.

Q. HOW DID YOU ESTIMATE A FAIR AND REASONABLE ROE ON SDG&E'S TRANSMISSION INVESTMENTS?

A. I estimated a fair and reasonable ROE on the Company's transmission assets using a two-step approach. First, I applied standard ROE estimation methodologies to a proxy group of combination gas and electric utilities with assets similar to the Company's. Second, in order to recognize the Company's much higher degree of risk relative to that of the proxy group, I recommended a ROE at the upper end of the range of the results from the various methodologies.

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING SDG&E'S COST OF COMMON EQUITY.

Q. I have examined SDG&E's risks and concluded that its risk environment far exceeds the industry average. It is my opinion that a fair, reasonable ROE for SDG&E is 11.2%. A ROE of 11.2% for SDG&E is required in order for the Company to: (i) attract capital on reasonable terms, (ii) maintain its financial integrity, (iii) earn a return commensurate with returns on comparable risk investments, and (iv) meet the Commission's policy of encouraging greater capital investments in transmission and promoting participation in transmission organizations.

Q. In reaching this conclusion, I have employed the traditional cost of capital estimating methodologies which assume business-as-usual circumstances, and then I performed a risk adjustment in order to account for SDG&E's much higher than average investment risks. My ROE recommendation is derived from cost of capital studies that I performed using the financial models available to me and from the application of my professional judgment to the results. I applied various cost of capital methodologies, including the Discounted Cash Flow ("DCF"), Risk Premium, and Capital Asset Pricing Model ("CAPM"), to a group of investment-grade dividend-paying combination gas and electric utilities. Those companies were required to have the majority of their revenues from regulated electric utility operations. I have also surveyed and analyzed the historical risk premiums in the utility industry and risk premiums allowed by regulators as indicators of the appropriate risk premium for the electric utility industry.

The upper end of the results from the various methodologies is required in order to account for SDG&E' much higher than average investment risk compared to other regulated utilities. As explained fully later in my testimony, this adjustment is based on SDG&E's higher degree of investment risk, as evidenced, among other factors, by its higher than average beta risk measure and its higher degree of regulatory risk. The ROE of 11.2% includes a 50 basis points adder which is consistent with FERC policy of applying an incentive ROE adder in order to recognize continuing participation in a regional transmission organization ("RTO"). I do consider my recommended ROE as barebones given the extraordinary unresolved risks due to wildfires regulation in California, as discussed later.

My recommended rate of return reflects the application of my professional judgment to the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses and SDG&E' higher than average investment risk.

Q. WOULD IT BE IN THE BEST INTERESTS OF RATEPAYERS FOR THE COMMISSION TO ADOPT YOUR RECOMMENDED 11.2% ROE FOR SDG&E'S ELECTRICITY TRANSMISSION UTILITY OPERATIONS?

A. Yes. My analysis shows that a conservative ROE of 11.2% is required to fairly compensate investors, maintain the Company's credit strength, and attract the capital needed for utility infrastructure and reliability capital investments. Adopting a lower ROE would increase costs for ratepayers.

Q. PLEASE EXPLAIN HOW LOW ALLOWED ROES CAN INCREASE BOTH THE FUTURE COST OF EQUITY AND DEBT FINANCING.

A. If a utility is authorized a ROE below the level required by equity investors, the utility will find it difficult to access the equity market through common stock issuance at its current market price. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As the company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on the company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that SDG&E has access to capital markets for its capital needs, a fair and reasonable authorized ROE of 11.2% is required.

The Company must secure outside funds from capital markets to finance required utility plant and equipment investments irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Thus, rate relief requirements and supportive regulatory treatment, including approval of my recommended ROE, are essential requirements.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into three broad sections:

(i) Regulatory Framework and Rate of Return;

(ii) Cost of Equity Estimates; and

(iii) Summary and Recommendation.

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of DCF, Risk Premium, and CAPM tests. In the third section, the results from the various approaches used in determining a fair return are summarized and the Company's higher relative risks are discussed.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE REGULATION.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate SDG&E's cost of common equity capital.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE ROE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va*, 262 U.S. 679 (1923), and

2. *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

The *Bluefield* case set the standard against which just and reasonable rates of return are measured:

> *A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public <u>equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties</u> ... The <u>return should be reasonable</u>, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to <u>maintain and support its credit and enable it to raise money</u> necessary for the proper discharge of its public duties.*

Bluefield Water Works & Improvement Co., 262 U.S. at 692 (emphasis added).

The *Hope* case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the *Bluefield* case and recognized that revenues must cover "capital costs." The Court stated:

> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard <u>the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks</u>. That return, moreover, should be sufficient to <u>assure confidence in the financial integrity</u> of the enterprise, so as to maintain its credit and attract capital.*

Hope Natural Gas Co., 320 U.S. at 603 (emphasis added).

The United States Supreme Court reiterated the criteria set forth in *Hope* in *Fed. Power Comm'n v. Memphis Light, Gas & Water Div.*, 411 U.S. 458

(1973), in *Permian Basin Rate Cases*, 390 U.S. 747 (1968), and most recently in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989). In the *Permian Basin Rate Cases*, the Supreme Court stressed that a regulatory agency's rate of return order should --

> *reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed.*

Permian Basin Rate Cases, 390 U.S. at 792.

Therefore, the "end result" of this Commission's decision should be to allow SDG&E the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the Company's financial integrity, and (3) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (*e.g.*, bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

While utilities like SDG&E enjoy varying degrees of monopoly in the sale of public utility services, they, or their parent companies, must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital, including the capital investments required to support the transmission grid. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on equity. In order to attract the necessary capital, transmission facilities must compete with alternative uses of capital and offer a return commensurate with the associated risks.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. The capital markets translate these differences in risk into differences in required return, in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the required return on capital is set by supply and demand and is influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF THE COMPANY'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side of capital markets, the other to the demand side.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect the returns on investments of comparable risk to be the same. If not, rational investors will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract capital funds unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk.

On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments equals, or exceeds, the company's cost of capital. This principle suggests that a regulatory board should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The cost of debt funds can be ascertained easily from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments.

Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt based on the utility's capital structure, in order to arrive at the overall cost of capital (overall rate of return).

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR ROE?

A. The basic premise is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The "attraction of capital" standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define "fair return" as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

III. COST OF EQUITY CAPITAL ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR ROE FOR SDG&E?

A. I employed three methodologies: (1) the DCF methodologies, (2) the CAPM, and (3) the Risk Premium. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to SDG&E. I first applied the aforementioned methodologies to a reference group of combination gas and electric utilities and, secondly, I recommended a ROE at the upper end of the range of the results from the various methodologies in order to recognize the Company's much higher degree of risk relative to that of the proxy group.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

As I have stated, there are three broad generic methods available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methods are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one method may very well vary depending on unusual circumstances in capital market conditions.

Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the method and on the reasonableness of the proxies used to validate the theory and apply the method. Each method has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of a stock's price or the cost of equity.

Q. ARE THERE ANY PRACTICAL DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN THE CURRENT ENVIRONMENT OF VOLATILITY IN CAPITAL MARKETS AND ECONOMIC UNCERTAINTY?

A. Yes, there are. The traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the instability and volatility in the capital markets and the uncertain economy both in the U.S. and abroad. This is not only because stock prices can be volatile, but also because utility company historical data have become less meaningful for an industry experiencing substantial change, for example, the transition to stringent renewable standards and the need to secure vast amounts of external capital over the next decade, regardless of capital market conditions. Past earnings and dividend trends may simply not be indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including declining customer usage, emerging risks attributable to technological change such as distributed generation, and falling margins. As a result, this historical data may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be necessarily representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available.

In short, given the volatility in capital markets and economic uncertainties, the utilization of multiple methodologies is critical, and reliance on a single methodology is highly hazardous.

A. DCF Estimates

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, stock price, and book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, *Regulatory Finance*, and Chapter 8 of my new reference text, *The New Regulatory Finance*. The standard DCF model requires the following main assumptions: (1) a constant average growth trend for both dividends and earnings, (2) a stable dividend payout policy, (3) a discount rate in excess of the expected growth rate, and (4) a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE SDG&E'S COST OF EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to a group of investment-grade, dividend-paying, combination electric and gas utilities covered in Value Line's Electric Utility group. The proxy companies were required to have the majority of their revenues from regulated operations, to have an investment grade credit rating, pay dividends, and not be involved in mergers/acquisitions.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0), and the expected long-term growth (g). The expected dividend (D_1) in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

Q. HOW DID YOU ESTIMATE THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL?

A. From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. This is because the current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the dividend yields reported in Zacks Investment Research web site ("Zacks") for each company in the peer group as of early September 2018. Basing dividend yields on average results from a large group of companies reduces the concern that the vagaries of individual company stock prices will result in an unrepresentative dividend yield.

Q. WHY DID YOU MULTIPLY THE SPOT DIVIDEND YIELD BY (1 + g) RATHER THAN BY (1 + 0.5g)?

A. Some analysts multiply the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) rather than the conventional one plus the expected growth rate (1 + g). This procedure understates the return expected by the investor.

The fundamental assumption of the basic annual DCF model is that dividends are received annually at the end of each year and that the first dividend is to be received one year from now. Thus, the appropriate dividend to use in a DCF model is the full prospective dividend to be received at the end of the year. Since the appropriate dividend to use in a DCF model is the prospective dividend one year from now rather than the dividend one-half year from now, multiplying the spot dividend yield by (1 + 0.5g) understates the proper dividend yield.

Moreover, the basic annual DCF model ignores the time value of quarterly dividend payments and assumes dividends are paid once a year at the end of the year. Multiplying the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality of quarterly dividend payments. Use of this method is conservative in the sense that the annual DCF model fully ignores the more frequent compounding of quarterly dividends.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined the consensus growth estimate developed by professional analysts. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.

Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks. I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecasts as additional proxies.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO ELECTRIC UTILITIES?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore redundant. Second, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts. This considerable literature is summarized in Chapter 9 of my most recent textbook, *The New Regulatory Finance*.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH TO APPLY THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, ROE, as follows:

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends
b = expected retention ratio
ROE = expected return on book equity

Q. DO YOU HAVE ANY RESERVATIONS IN REGARDS TO THE SUSTAINABLE GROWTH METHOD?

A. Yes, I do. First, the sustainable method of predicting growth contains a logic trap: the method requires an estimate of expected return on book equity to be implemented. But if the expected return on book equity input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Second, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

Q. DID YOU CONSIDER DIVIDEND GROWTH IN APPLYING THE DCF MODEL?

A. No, not at this time. The reason is that as a practical matter, while there is an abundance of earnings growth forecasts, there are very few forecasts of dividend growth. Moreover, it is widely expected that some utilities will continue to lower their dividend payout ratios over the next several years in response to heightened business risk and the need to fund very large construction programs over the next decade. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks and finance large infrastructure investments. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Zacks Investment, First Call Thompson, Reuters, Yahoo Finance, and Multex provide comprehensive compilations of investors' earnings forecasts. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which accounts for 65% of the ranking.

Q. DR. MORIN, HOW DID YOU APPROACH THE COMPOSITION OF COMPARABLE GROUPS IN ORDER TO ESTIMATE SDG&E'S COST OF EQUITY WITH THE DCF METHOD?

A. Because SDG&E is not publicly traded, the DCF model cannot be applied to SDG&E and proxies must be used. There are two possible approaches in forming proxy groups of companies.

The first approach is to apply cost of capital estimation techniques to a select group of companies directly comparable in risk to SDG&E. These companies are chosen by the application of stringent screening criteria to a universe of electric utility stocks in an attempt to identify companies with the same investment risk as SDG&E. Examples of screening criteria include bond rating, beta risk, size, percentage of revenues from electric utility operations, and common equity ratio. The end result is a small sample of companies with a risk profile similar to that of SDG&E, provided the screening criteria are defined and applied correctly.

The second approach is to apply cost of capital estimation techniques to a large group of electric utilities representative of the electric utility industry average and then make adjustments to account for any difference in investment risk between the company and the industry average, if any. As explained below, in view of substantial changes in circumstances in the electric utility industry, I have chosen the latter approach.

In the current unstable capital market environment, it is important to select relatively large sample sizes representative of the electric utility industry as a whole, as opposed to small sample sizes consisting of a handful of companies. This is because the equity market as a whole and electric utility industry capital market data is volatile at this time. As a result of this volatility, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth are mitigated. Utilizing a large portfolio of companies reduces the influence of either overestimating or underestimating the cost of equity for any one individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend to cancel out owing to the law of large numbers, provided that the errors are independent.[1] The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

Moreover, small samples are subject to measurement error, and in violation of the Central Limit Theorem of statistics.[2] From a statistical

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[1] If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^{\,2} + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$

As N gets progressively larger, the variance gets smaller and smaller.

[2] The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. If the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

standpoint, reliance on robust sample sizes mitigates the impact of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring.

The point of all this is that the use of a handful of companies in a highly fluid and unstable industry produces fragile and statistically unreliable results. A far safer procedure is to employ large sample sizes representative of the industry as a whole and apply subsequent risk adjustments to the extent that the company's risk profile differs from that of the industry average.

Q. CAN YOU DESCRIBE YOUR PROXY GROUP FOR SDG&E'S ELECTRIC UTILITY BUSINESS?

A. As proxies for SDG&E, I examined a group of investment-grade dividend-paying combination gas and electric utilities covered in Value Line's Electric Utility industry group, meaning that these companies all possess utility assets similar to SDG&E's. I began with all the companies designated as combination gas and electric utilities that are also covered in the Value Line Investment Survey as shown in Exhibit No. SD-0021. Fortis was added to the group since it owns several US combination gas and electric companies. Private partnerships, private companies, non-dividend-paying companies, and companies below investment-grade (with a Moody's bond rating below Baa3) were eliminated, as well as those companies whose market capitalization was less than $1 billion, in order to minimize any stock price anomalies due to thin trading.[3] The final groups of companies only include those companies with at least 50% of their revenues from regulated utility operations.

From the preliminary list of 29 companies shown on Exhibit No. SD-0021, and as shown on the accompanying notes in the last column of that exhibit, I excluded eleven companies marked with an X in Column 3. Column 4 shows the rationale for exclusion. The first excluded company was Avista Corp. on account of its ongoing acquisition of Hydro One. The second excluded company was Empire District Electric, which recently combined with a subsidiary of Liberty Utilities Co., the wholly owned regulated utility business subsidiary of Algonquin Power & Utilities Corp. The third excluded company was Entergy Corp. on account of its ongoing corporate restructuring and nuclear exposure. The fourth company was MDU Resources because its revenues from regulated electric utility operations were less than 50%. The fifth excluded company was Pepco Holdings, which has been merged with Exelon. The sixth excluded company was PG&E since it has suspended dividends. The seventh company excluded was SCANA on account of its nuclear construction exposure. Unitil was the eighth company excluded because of its very small size and because it is not covered in the Value Line database. CenterPoint and Vectren were excluded on account of the ongoing acquisition of the latter by the former company.

[3] This is necessary in order to minimize the well-known thin trading bias in measuring beta. Unitil was excluded for this reason.

Finally, the eleventh excluded company was TECO Energy which has been acquired by Emera.

The final group of 18 companies that comprise the proxy group is shown on Exhibit No. SD-0022. I stress that this proxy group must be viewed as a portfolio of comparable risk. It would be inappropriate to select any particular company or subset of companies from this group and infer the cost of common equity from that company or subset alone.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR SDG&E USING VALUE LINE GROWTH PROJECTIONS?

A. Exhibit No. SD-0023 displays the DCF analysis using Value Line growth projections for the 18 companies in SDG&E's proxy group. As shown on column 3, line 20 of Exhibit No. SD-0023, the average long-term earnings per share growth forecast obtained from Value Line is 6.44% for SDG&E's proxy group. Combining this growth rate with the average expected dividend yield of 3.47% shown on column 4, line 20 produces an estimate of equity costs of 9.92% for the proxy group, as shown on column 5, line 20. Recognition of flotation costs brings the cost of equity estimate to 10.10% for the group, shown on Column 6, line 20. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR SDG&E USING ANALYSTS' CONSENSUS GROWTH FORECASTS?

A. Exhibit No. SD-0024displays the DCF analysis using analysts' consensus growth forecasts for the 18 companies in SDG&E's proxy group. Please note that the growth forecasts for MGE Energy was drawn from Value Line's growth forecast since the Zacks growth forecast were not available for that company.

As shown on column 3, line 21 of Exhibit No. SD-0024, the average long-term earnings per share growth forecast obtained from analysts is 5.48% for the group. Combining this growth rate with the average expected dividend yield of 3.45% shown on column 4, line 21, produces an estimate of equity costs of 8.93% for SDG&E's proxy group unadjusted for flotation cost, as shown on column 5, line 21. Recognition of flotation costs brings the cost of equity estimate to 9.11%, shown on Column 6, line 21.

Q. PLEASE SUMMARIZE THE DCF ESTIMATES FOR SDG&E.

A. Table 1 below summarizes the DCF estimates for SDG&E:

Table 1: DCF Estimates for SDG&E

DCF STUDY	ROE
Electric Utilities Value Line Growth	10.10%
Electric Utilities Analysts Growth	9.11%

Q. DR. MORIN, PLEASE PROVIDE AN OVERVIEW OF YOUR RISK PREMIUM ANALYSES.

A. In order to quantify the risk premium for SDG&E, I have performed four risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology and the other two studies deal with the risk premiums that exist in the electric utility industry.

B. CAPM Estimates

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM ("ECAPM"). The CAPM is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + [\beta(R_M - R_F)]$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by $\beta(R_M - R_F)$. The latter bracketed expression is known as the market risk premium ("MRP"). To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the MRP, ($R_M - R_F$).

For the risk-free rate, I used 4.3%, based on forecast interest rates on long-term U.S. Treasury bonds.

For beta, I used 0.65 based on Value Line estimates.

For the MRP, I used 7.0% based on historical studies and some additional checks. These inputs to the CAPM are explained below.

Q. HOW DID YOU ARRIVE AT YOUR RISK-FREE RATE ESTIMATE OF 4.3% IN YOUR CAPM AND RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. I relied on noted economic forecasts which call for a rising trend in interest rates in response to the recovering economy, renewed inflation, and record high federal deficits. Value Line, Global Insight, the Congressional Budget Office, the Bureau of Labor Statistics, the Economic Report of the President, and the U.S. Energy Information Administration all project higher long-term Treasury bond rates in the future.

Q. WHY DID YOU RELY ON LONG-TERM BONDS INSTEAD OF SHORT-TERM BONDS?

A. The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term Treasury bills or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (*e.g.*, pension funds and insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long term. The same expectation should be embodied in the risk-free rate used in applying the CAPM model. It stands to reason that the yields on 30-year Treasury bonds will more closely incorporate within their yields the inflation expectations that influence the prices of common stocks than do short-term Treasury bills or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yields on such securities should be used as proxies for the risk-free rate in applying the CAPM. Therefore, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. DR. MORIN, ARE THERE OTHER REASONS WHY YOU REJECT SHORT-TERM INTEREST RATES AS PROXIES FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. Yes. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE IN APPLYING THE CAPM?

A. All the noted interest rate forecasts that I am aware of point to significantly higher interest rates over the next several years. The table below reports the forecast yields on 30-year US Treasury bonds from several prominent sources, including the Congressional Budget Office, Bureau of Labor Statistics, U.S. Energy Information Administration, HIS (formerly Global Insight), Value Line, and the Economic Report of the President.

Table 2: Forecast Yields on 30-year U.S. Treasury Bonds

Value Line Economic Forecast	3.80
U.S. Energy Information Administration	4.57
Bureau of Labor Statistics	5.68
Congressional Budget Office	4.20
Economic Report of the President	4.20
White House Budget 2018	4.10
IHS (Global Insight)	3.76
AVERAGE	**4.33**

The average 30-year long-term bond yield forecast from the seven sources is 4.3%, and the individual forecasts are quite consistent as they are closely clustered around the average. Based on this evidence, a long-term bond yield forecast of 4.3% is a reasonable estimate of the expected risk-free rate for purposes of forward-looking CAPM/ECAPM and Risk Premium analyses in the current economic environment.

Q. DR. MORIN, WHY DID YOU IGNORE THE CURRENT LEVEL OF INTEREST RATES IN DEVELOPING YOUR PROXY FOR THE RISK-FREE RATE IN A CAPM ANALYSIS?

A. I relied on projected long-term Treasury interest rates for three reasons. First, investors price securities on the basis of long-term expectations, including interest rates. Cost of capital models, including both the CAPM and DCF models, are prospective (*i.e.*, forward-looking) in nature and must take into account current market expectations for the future because investors price securities on the basis of long-term expectations, including interest rates. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market. While investors examine history as a guide to the future, it is the expectations of future events that influence security values and the cost of capital.

Second, investors' required returns can and do shift over time with changes in capital market conditions, hence the importance of considering interest rate forecasts. The fact that organizations such as Value Line, IHS (Global Insight), EIA, and CBO among many others devote considerable expertise and resources to developing an informed view of the future, and the fact that investors are willing to purchase such expensive services confirm the importance of economic/financial forecasts in the minds of investors. Moreover, the empirical evidence demonstrates that stock prices do indeed reflect prospective financial input data.

Third, given that this proceeding is to provide ROE estimates for future proceedings, forecast interest rates are far more relevant. The use of interest rate forecasts is no different than the use of projections of other financial variables in DCF analyses.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta" (β), or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. It indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation that are reflected in investors' return requirements.

As an operating subsidiary of Sempra Energy ("Sempra"), SDG&E is not publicly traded, and therefore, proxies must be used. As shown on Exhibit No. SD-0025, the average beta for the SDG&E proxy group of companies is 0.65. I also note that SDG&E's parent company beta is one of the highest in the industry at 0.75. More on this later.

Based on these results, I shall use 0.65, as an estimate for the beta applicable to the peer group.

Q. WHAT MRP DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the MRP, I used 7.0%. This estimate was based on the results of historical studies of long-term risk premiums and on two additional checks. Specifically, the historical MRP estimate is based on the results obtained in Duff & Phelps' 2017 Valuation Handbook (formerly published by Morningstar and earlier by Ibbotson Associates), which compiles historical returns from 1926 to 2016. This well-known study summarized on Exhibit 2.3 of the handbook shows that a very broad market sample of common stocks outperformed long-term U.S. Government bonds by 6.0%. The historical MRP over the income component of long-term U.S. Government bonds rather than over the total return is 7.0%.

The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. The income component of total bond return (*i.e.*, the coupon rate) is a far better estimate of expected return than the total return (*i.e.*, the coupon rate + capital gain), because both realized capital gains and realized losses are largely unanticipated by bond investors. The long-horizon (1926-2017) MRP is 7.0%.

As a first check on my 7.0% MRP estimate, I examined the historical return on common stocks in real terms (inflation-adjusted) over the 1926-2016 period and added current inflation expectations to arrive at a current inflation-adjusted common stock return. According to the Duff & Phelps study, the average historical return on common stocks averaged 12.0% over the 1926-2016 period while inflation averaged 3.0% over the same period, implying a real return of 9.0% (12.0% - 3.0% = 9.0%). With current long-term inflation expectations of 2.1%[4], the inflation-adjusted return on common stock becomes 11.0% (9.0% + 2.1% = 11.1%). Given the forecast yield of 4.3%, the implied MRP is 6.8% (11.1% - 4.3% = 6.8%) which is almost identical to the 7.0% estimate.

As a second check on the 7.0% estimate, I examined Value Line's dividend yield and growth forecasts for the 1700 stocks in the Value Line Stock Index, that is, for the broad U.S. economy[5]. Value Line's dividend yield forecast for the latter is 2.0%, and its forecast 3- to 5-year appreciation potential for these companies is 40%. The latter figure for the 4-year period (the midpoint of the 3- to 5-year forecast period) implies an annual growth potential of 8.8%. Adding the 2.0% dividend yield to this annual growth rate produces a market return of 10.8%. Subtracting the current yield of 3.0% on 30-year Treasury bonds from the market return produces a market risk premium of 7.8%. Subtracting the forecast yield of 4.3% instead of the current yield produces a market risk premium of 6.5%. The resulting MRP range of 6.5% - 7.8% (midpoint 7.2%) is therefore quite consistent with my MRP estimate of 7.0%

[4] 30-year U.S. Treasury bonds are currently trading at a 3.0% yield while 30-year inflation-adjusted bonds are trading at an approximate yield of 0.9%, implying a long-term inflation rate expectation of 2.1%.

[5] *See* Value Line Summary and Index September 7, 2018 issue.

Q. ON WHAT MATURITY BOND DOES THE DUFF &PHELPS HISTORICAL RISK PREMIUM DATA RELY?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2016 period covered in the Duff & Phelps Study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. Given that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Duff & Phelps study, the difference in yield is not material.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MRP ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the MRP with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate MRP minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Since I found no evidence that the MRP in common stocks has changed over time, that is, no significant serial correlation in the Duff & Phelps study prior to that time, it is reasonable to assume that these quantities will remain stable in the future.

Q. SHOULD STUDIES OF HISTORICAL RISK PREMIUMS RELY ON ARITHMETIC AVERAGE RETURNS OR ON GEOMETRIC AVERAGE RETURNS?

A. Whenever relying on historical risk premiums, only arithmetic average returns over long periods are appropriate for forecasting and estimating the cost of capital, and geometric average returns are not.[6]

Q. PLEASE EXPLAIN HOW THE ISSUE OF WHAT IS THE PROPER "MEAN" ARISES IN THE CONTEXT OF ANALYZING THE COST OF EQUITY?

A. The issue arises in applying methods that derive estimates of a utility's cost of equity from historical relationships between bond yields and earned returns on equity for individual companies or portfolios of several companies. Those methods produce series of numbers representing the annual difference between bond yields and stock returns over long historical periods. The question is how to

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[6] *See* Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, chapter 11 (1994); Roger A. Morin, *The New Regulatory Finance: Utilities' Cost of Capital*, chapter 4 (2006); Richard A Brealey, *et al.*, *Principles of Corporate Finance* (8th ed. 2006).

translate those series into a single number that can be added to a current bond yield to estimate the current cost of equity for a stock or a portfolio. Calculating geometric and arithmetic means are two ways of converting series of numbers to a single, representative figure.

Q. IF BOTH ARE "REPRESENTATIVE" OF THE SERIES, WHAT IS THE DIFFERENCE BETWEEN THE TWO?

A. Each represents different information about the series. The geometric mean of a series of numbers is the value which, if compounded over the period examined, would have made the starting value to grow to the ending value. The arithmetic mean is simply the average of the numbers in the series. Where there is any annual variation (volatility) in a series of numbers, the arithmetic mean of the series, which reflects volatility, will always exceed the geometric mean, which ignores volatility. Because investors require higher expected returns to invest in a company whose earnings are volatile than one whose earnings are stable, the geometric mean is not useful in estimating the expected rate of return which investors require to make an investment.

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE TO ILLUSTRATE THIS DIFFERENCE BETWEEN GEOMETRIC AND ARITHMETIC MEANS?

A. Yes. The following table compares the geometric and arithmetic mean returns of a hypothetical Stock A, whose yearly returns over a ten-year period are very volatile, with those of a hypothetical Stock B, whose yearly returns are perfectly stable during that period. Consistent with the point that geometric returns ignore volatility, the geometric mean returns for the two series are identical (11.6% in both cases), whereas the arithmetic mean return of the volatile stock (26.7%) is much higher than the arithmetic mean return of the stable stock (11.6%):

Table 3: Geometric vs. Arithmetic Returns

YEAR	STOCK A	STOCK B
1998	50.0%	11.6%
1999	-54.7%	11.6%
2000	98.5%	11.6%
2001	42.2%	11.6%
2002	-32.3%	11.6%
2003	-39.2%	11.6%
2004	153.2%	11.6%
2015	-10.0%	11.6%
2016	38.9%	11.6%
2017	20.0%	11.6%
Arithmetic Mean Return	**26.7%**	**11.6%**
Geometric Mean Return	**11.6%**	**11.6%**

If relying on geometric means, investors would require the same expected return to invest in both of these stocks, even though the volatility of returns in Stock A is very high while Stock B exhibits perfectly stable returns. That is clearly contrary to the most basic financial theory, that is, the higher the risk the higher the expected return.

Chapter 4 Appendix A of my book *The New Regulatory Finance* contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital. Briefly, the disparity between the arithmetic average return and the geometric average return raises the question as to what purposes should these different return measures be used. The answer is that the geometric average return should be used for measuring historical returns that are compounded over multiple time periods. The arithmetic average return should be used for future-oriented analysis, where the use of expected values is appropriate. It is inappropriate to average the arithmetic and geometric average return; they measure different quantities in different ways.

Q. DR. MORIN, IS YOUR MRP ESTIMATE OF 7.0% CONSISTENT WITH THE ACADEMIC LITERATURE ON THE SUBJECT?

A. Yes, it is, although in the upper portion of the range. In their authoritative corporate finance textbook, Professors Brealey, Myers, and Allen[7] conclude from their review of the fertile literature on the MRP that a range of 5% to 8% is reasonable for the MRP in the United States. My own survey of the MRP literature, which appears in Chapter 5 of my latest textbook, *The New Regulatory Finance*, is also quite consistent with this range.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF THE AVERAGE RISK UTILITY'S COST OF EQUITY USING THE CAPM APPROACH?

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[7] Richard A. Brealey, Stewart C. Myers, and Paul Allen, *Principles of Corporate Finance*, 8th Edition, Irwin McGraw-Hill, 2006.

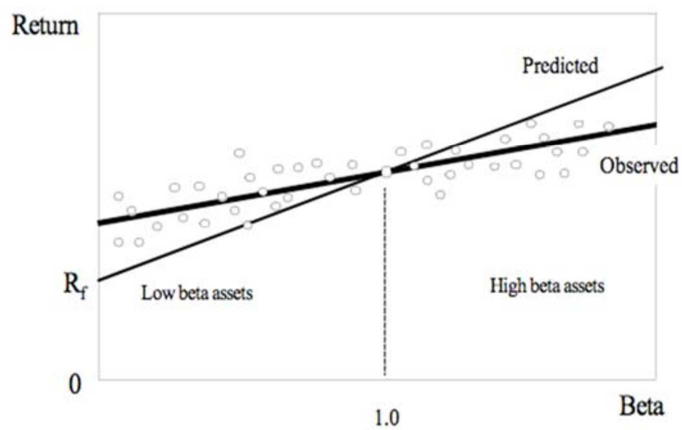
A. Inserting those input values into the CAPM equation, namely a risk-free rate of 4.3%, a beta of 0.65, and a MRP of 7.0%, the CAPM estimate of the cost of common equity is: 4.3% + 0.65 x 7.0% =8.85%. This estimate becomes 9.05% with flotation costs, discussed later in my testimony.

Q. CAN YOU DESCRIBE YOUR APPLICATION OF THE EMPIRICAL VERSION OF THE CAPM?

A. There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 6 of my latest book, *The New Regulatory Finance*. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \alpha + \beta \text{ x } (MRP - \alpha)$$

where the symbol alpha, α , represents the "constant" of the risk-return line, MRP is the market risk premium (R_M - R_F), and the other symbols are defined as usual.

Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25 (R_M - R_F) + 0.75 \beta \quad (R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM.[8] Thus, it is reasonable to apply a conservative alpha adjustment.

Appendix A contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\ \beta\ (R_M - R_F)$$

Inserting 4.3% for the risk-free rate R_F, a MRP of 7.0% for (R_M - R_F) and a beta of 0.65 in the above equation, the return on common equity is 9.46%. This estimate becomes 9.66% with flotation costs, discussed later in my testimony.

Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?

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8 The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. Value Line, Bloomberg, and Merrill Lynch betas are adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% weight to the measured raw beta and approximately 33% weight to the prior value of 1.0 for each stock:

$$\beta_{adjusted} = 0.33 + 0.66\ \beta_{raw}$$

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line, Bloomberg, and Morningstar. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease in beta. The observed return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

A. The table below summarizes the common equity estimates obtained from the CAPM studies.

Table 4: CAPM Estimates for SDG&E

CAPM Method	ROE
Traditional CAPM	9.1%
Empirical CAPM	9.7%

C. Historical Risk Premium Estimate

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY USING TREASURY BOND YIELDS.

A. A historical risk premium for the utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1931-2016 period, using Standard and Poor's Utility Index ("S&P Index") as an industry proxy. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term Treasury bond return for that year. Please see Exhibit No. SD-0026 for this analysis

As shown on Exhibit No. SD-0026, the average risk premium over the period was 5.6% over long-term Treasury bond yields and 6.2% over the income component of bond yields. As discussed previously, the latter is the appropriate risk premium to use. Given the risk-free rate of 4.3%, and using the historical estimate of 6.2% for bond returns, the implied cost of equity is 4.3% + 6.2% = 10.5% without flotation costs and 10.7% with the flotation cost allowance.

Q. DR. MORIN, ARE RISK PREMIUM STUDIES WIDELY USED?

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, economists, and expert witnesses. Most college-level corporate finance or investment management texts, including *Investments* by Bodie, Kane, and Marcus,[9] which is a recommended textbook for CFA (Chartered Financial Analyst) certification and examination, contain detailed conceptual and empirical discussion of the risk premium approach. Risk Premium analysis is typically recommended as one of the three leading methods of estimating the cost of capital. Professor Brigham's best-selling corporate finance textbook, for example, *Corporate Finance: A Focused Approach*,[10] recommends the use of risk premium studies, among others. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are certainly well versed in the use of this method. The only difference is that I rely on long-term Treasury yields instead of the yields on A-rated utility bonds.

Q. ARE YOU CONCERNED ABOUT THE REALISM OF THE ASSUMPTIONS THAT UNDERLIE THE HISTORICAL RISK PREMIUM METHOD?

A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when

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9 McGraw-Hill Irwin, 2002.

10 Fourth edition, South-Western, 2011.

measured over short time periods. By ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would be reluctant to invest money.

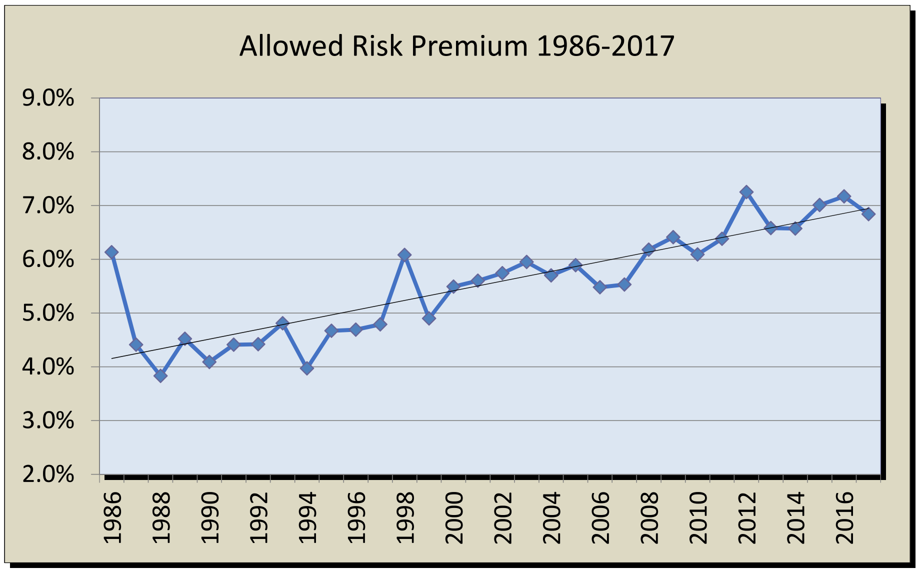
D. Allowed Risk Premiums

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE ELECTRIC UTILITY INDUSTRY.

A. To estimate the electric utility industry's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the 1986-2017 period for which data were available, relative to the contemporaneous level of the long-term Treasury bond yield. Please see Exhibit No. SD-0027 for this analysis.

This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, CAPM, Risk Premium, *etc*.) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates (now S&P Global Intelligence) and easily verifiable from prior issues of that same publication and past commission decision archives.

The average ROE spread over long-term Treasury yields was 5.55% over the entire 1986-2017 period for which data were available. The graph below shows the year-by-year allowed risk premium. The escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.

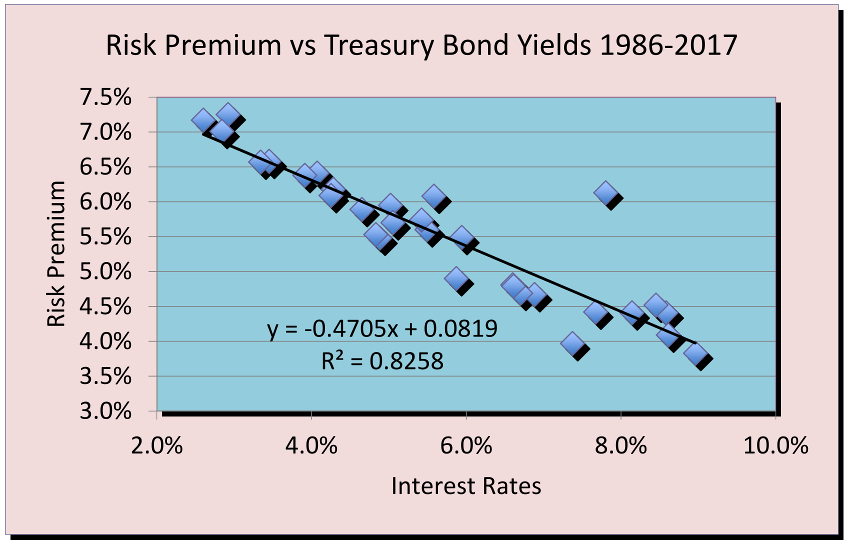


A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1986-2017 period:

$$RP = 8.1900 - 0.4705\ YIELD \qquad R^2 = 0.82$$

The relationship is highly statistically significant[11] as indicated by the very high R^2. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.

[11] The coefficient of determination R^2, sometimes called the "goodness of fit measure," is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the



Inserting the long-term Treasury bond yield of 4.3% in the above equation suggests a risk premium estimate of 6.2%, implying a cost of equity of 10.5%. The latter estimate is very close to the result of the historical risk premium study which yielded the exact same risk premium of 6.2%.

Q. DO INVESTORS TAKE INTO ACCOUNT ALLOWED RETURNS IN FORMULATING THEIR RETURN EXPECTATIONS?

A. Yes, they do. Investors do indeed take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and S&P Global Intelligence. Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns.

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explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. Table 5 below summarizes the ROE estimates obtained from the two risk premium studies.

Table 5: Risk Premium Estimates

Risk Premium Method	ROE
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

E. Need for Flotation Cost Adjustment

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that issuing common equity capital is not free. Flotation costs associated with stock issues are very similar to the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (*e.g.*, printing, legal, prospectus). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation costs requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.53%.

According to the empirical finance literature discussed in Appendix B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, as the argument goes, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure, although simple in implementation, is not considered appropriate, however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely. It would be unfair to burden the current generation of ratepayers with the full costs of raising capital when the benefits of that capital extend indefinitely. The common practice of capitalizing rather than expensing eliminates the intergenerational transfers that would prevail if today's ratepayers were asked to bear the full burden of flotation costs of bond/stock issues in order to finance capital projects designed to serve future as well as current generations. Moreover, expensing flotation costs requires an estimate of the market pressure effect for each individual issue, which is likely to prove unreliable. A more reliable approach is to estimate market pressure for a large sample of stock offerings rather than for one individual issue.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated with and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. DR. MORIN, CAN YOU PLEASE ELABORATE ON THE MARKET PRESSURE COMPONENT OF FLOTATION COST?

A. The indirect component, or market pressure component of flotation costs represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue, reflecting the basic economic fact that when the supply of securities is increased following a stock or bond issue, the price falls. The market pressure effect is real, tangible, measurable, and negative. According to the empirical finance literature cited in Appendix B, the market pressure component of the flotation cost adjustment is approximately 1% of the gross proceeds of an issuance. The announcement of the sale of large blocks of stock produces a decline in a company's stock price, as one would expect given the increased supply of common stock.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE SDG&E THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its owners, in this case, Sempra. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

IV. SUMMARY AND RECOMMENDATION ON COST OF EQUITY

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my estimate of SDG&E's cost of common equity, I performed

- a DCF analysis on a group of investment-grade dividend-paying combination gas and electric utilities using Value Line's growth forecasts;
- a DCF analysis on a group of investment-grade dividend-paying combination gas and electric utilities using analysts' growth forecasts;
- a traditional CAPM using current market data;
- an empirical approximation of the CAPM using current market data;
- historical risk premium data from electric utility industry aggregate data, using the prospective yield on long-term US Treasury bonds; and
- allowed risk premium data from electric utility industry aggregate data, using the prospective yield on long-term US Treasury bonds.

The results are summarized in the table below.

Table 6: Summary of Results

STUDY	**ROE**
DCF Combination Elec & Gas Util Value Line Growth	10.1%
DCF Combination Elec & Gas Util Analysts Growth	9.1%
Traditional CAPM	9.1%
Empirical CAPM	9.7%
Hist. Risk Premium Elec Utility Industry	10.7%
Allowed Risk Premium	10.5%

The results range from 9.1% to 10.7% with a midpoint of 9.9%. Based on all those results, I use the upper end of the range, 10.7%, as my initial estimated ROE for SDG&E. Consistent with FERC policy of applying an incentive ROE adder of 50 basis points in order to recognize continuing participation in a RTO, my recommended ROE for SDG&E becomes 11.2%. In view of the extraordinary and unresolved risks due to current wildfire California regulation, I do consider my recommended ROE of 11.2% as barebones.

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in the above table must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from the summary table and infer the cost of common equity from that number alone.

Q. SHOULD THE ROE BE SET AT THE UPPER END OF YOUR RECOMMENDED RANGE IN ORDER TO ACCOUNT FOR SDG&E BEING SUBSTANTIALLY RISKIER THAN THE AVERAGE ELECTRIC UTILITY?

A. Yes, it definitely should. The cost of equity estimates derived from the comparable group reflect the risk of the average electric utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier SDG&E should be set in the upper end of the range of results.

Q. DO INVESTORS PERCEIVE SDG&E AS A RISKIER THAN AVERAGE ELECTRIC UTILITY?

A. Yes, they definitely do. SDG&E's parent company beta is 0.75 compared to the average beta of 0.65 for the electric utilities group, a significant difference of 0.10. As shown earlier in my discussion of the CAPM, the beta coefficient occupies a central role in financial theory, and has been shown to be a sufficient and complete measure of risk for diversified investors.

Moreover, the two DCF results for Sempra shown on Exhibits SD-0023 and SD-0024, 13.04% and 11.52%, are by far the highest in the peer group, attesting to the Company's much higher investment risks. This is not surprising given that few if any other electric utilities confront the unique risk factors and challenges faced by SDG&E discussed below.

Q. CAN YOU BRIEFLY DISCUSS THE PRINCIPAL ASPECTS OF SDG&E'S BUSINESS RISK PROFILE WHICH DIFFERENTIATE THE COMPANY FROM ITS PEERS?

A. Yes. The Company faces several increased risks relative to its peers, hence its higher beta risk measure and higher DCF estimates. As shown in the testimony of SDG&E witness Don Widjaja, SDG&E has a comparatively high level of business, regulatory and financial risks compared to the proxy group of companies. The principal risk factors include: (1) Regulatory risks, (2) California's Renewable Portfolio Standards ("RPS") law, and (3) Transmission-related risks. I will now comment on each of the aforementioned risk elements.

Q. CAN YOU COMMENT ON SDG&E'S REGULATORY AND LEGISLATIVE RISKS?

A. The regulatory and legislative environment is highly uncertain in the California electric utility sector. This has had an immediate and serious impact on the credit rating agencies' assessment of SDG&E's regulatory risk.

California wildfires have created substantial credit and capital access challenges and have exposed SDG&E to potentially huge liabilities because of the so-called "inverse condemnation" doctrine. Under this doctrine, SDG&E may be held liable for wildfires-related damages regardless of fault even if the Company is deemed to have acted prudently. As a result, regulatory risks and the cost of capital have risen significantly given the possibility that recovery of such costs is disallowed by the CPUC. In fact, both S&P and Moody's have downgraded the

Company's bonds and placed its bonds under negative outlook for further downgrade.

In its May 2018 report following the earlier Negative Outlook determination in December 2017, Moody's stated:

> *"……our reassessment of the credit supportiveness of the California regulatory environment due to the rising risk associated with the wildfires and the potentially large contingent exposure created by the application of strict liability standard under inverse condemnation. That said, we acknowledge that there has been progress made towards addressing inverse condemnation at both a legislative and regulatory level in California but any changes may not be completed during this year's legislative session."*

Finally, on September 8, 2018 Moody's downgraded the Company's bonds and stated in its report:

> *"Today's rating action reflects that Senate Bill (SB 901), recently passed by both California legislative houses, did not repeal or change inverse condemnation such that all Californian utilities remain exposed to strict liability standards in the case of wildfires where utility equipment was determined to be the source of the fire, regardless of fault. The application of inverse condemnation is a unique risk factor affecting all California investor owned utilities that has weakened our assessment of the credit supportiveness of the California legislative and regulatory framework compared to other US regulatory environments."*

S&P reacted in a similar fashion. In its June 2018 credit report, S&P stated the following:

> *"- Regulated electric utilities in California face operational and financial risks from natural disasters that if left unresolved could trigger a deterioration in their credit quality.*
>
> *- Not only is California prone to wildfires and other natural disasters, but the legal doctrine of inverse condemnation in the state's common law potentially holds a utility financially responsible for wildfires if its facilities were a contributing cause of the wildfire, regardless of its negligence, and without allowing it a direct means to collect the wildfire costs from ratepayers.*

- The lack of predictability in California for utilities to consistently recover the costs of a wildfire from ratepayers places enormous risks and vulnerability on the utilities that is unlike any other regulatory jurisdiction in North America.

- The lack of predictability in California for utilities to consistently recover the costs of a wildfire from ratepayers places enormous risks and vulnerability on the utilities that is unlike any other regulatory jurisdiction in North America.

On September 5, 2018, S&P also downgraded the Company's bonds principally on account of the unaddressed longer-term wildfire risks, and stated in its report:

"The downgrade reflects the unaddressed longer-term risks associated with inverse condemnation. Although the California Legislature's approval of SB 901 addresses many of the near-term risks associated with wildfire costs borne by utilities, it does not deal with the longer-term issue of inverse condemnation. While SB 901 may empower the California Public Utilities Commission (CPUC) to allow electric utilities to recover some or all of the costs associated with wildfires, the burden on customers would eventually become unsustainable should the pace and intensity of destructive wildfires persist at current levels."

These risk concerns are not only clearly manifest in the Company's bonds but also in its common stock. As stated earlier, SDG&E has the second highest beta risk measure among electric utilities and the highest DCF cost of equity estimates.

In short, regulatory decisions that suggest the utility will not have regulatory support increase the Company's risk profile, and have led to SDG&E's credit rating downgrade from both S&P and Moody's. These downgrades have increased the Company's cost of capital, and thus, ultimately, the rates that customers will be required to pay.

Q. PLEASE COMMENT ON SDG&E'S CHALLENGE TO COMPLY WITH CALIFORNIA'S STRICT RENEWABLES PORTFOLIO STANDARDS.

A. Federal and State policies mandate higher use of renewable resources. In California, the RPS requires SDG&E to obtain 35% of sales from renewable electrical energy resources, among the strictest in the nation.

S&P's assessment of the impact of RPS on the industry is:

> *"Largely through legislation, the political process has engineered RPS, but it is the utilities that will ultimately be responsible for implementing the standards. We question whether state legislatures, or citizens (in the case of Colorado or Washington, where voter mandates initiated RPS), understand the full cost impact of the RPS programs on customer bills over the next 20 years. An equally important credit concern is the extent that utilities will be held responsible if unforeseen events prevent them from reaching targets. The willingness of regulatory commissions to adopt flexible compliance guidelines that exempt utilities from penalties if unexpected delays occur in meeting interim or final targets can mitigate this concern. And many states do have "off-ramps" that allow utilities to ratchet back RPS if they prove to be uneconomic".*[12]

The RPS requirements present new and increased risks to the Company by committing SDG&E to facilitate the integration of substantial amounts of clean, renewable energy into its grid and to enable electricity consumers to manage their electricity use more effectively. Uncertainty relating to the requirements for and technology of capital expenditures relating to these commitments increases business risk, in addition to the financing and cost recovery risks which increase financial risk.

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[12] S&P Ratings Direct "The Race for the Green: How Renewable Portfolio Standards Could Affect U.S. Utility Credit Quality" dated March 10, 2008.

For example, under the new RPS requirements, SDG&E is required to purchase certain types of energy under certain conditions at a rate established by the CPUC. The impact on the Company of this new obligation will depend on many factors, including the impact on the operations of the Company, the magnitude of the obligation, and the conditions under which the Company must make payments. An adverse impact on the Company's operations may reduce reliability and negatively impact business risk which would adversely impact credit quality.

Q. CAN YOU COMMENT ON THE COMPANY'S BUSINESS RISKS ASSOCIATED WITH TRANSMISSION?

A. Yes. With respect to the investment risks associated with transmission, three are noteworthy. First, there are risks associated with technological change. The proliferation of distributed generation and photovoltaic cell technologies suggests the potential reduction in transmission capacity and the prospect of stranded transmission costs. Second, the potentially conflicting multi-jurisdictional and federal-state aspects of transmission regulation concern investors. Third, and perhaps more important, are the huge capital expenditures faced by the Company, including the transmission capital expenditures required for increasing network reliability, increasing access to renewables, and promoting increased competition in the electricity market. The dominant role of the allowed ROE in determining the magnitude of investment capital has been recognized by FERC through its policies of incentive ROEs and transmission-related CWIP inclusion in rate base.

Q. ARE THERE OTHER MATERIAL BUSINESS RISKS FACED BY THE COMPANY?

A. Yes, there are. SDG&E faces increasingly stringent environmental laws and regulations which regulate the operation and modification of existing facilities, the construction and operation of new facilities, and the proper cleanup and disposal of hazardous waste and toxic substances. The Company is at risk for the direct cost of compliance as well as the economic consequences of any impact on operations.

SDG&E's customers today have more access to alternative energy sources (*i.e.*, self-generation, distributed generation, photovoltaic installations), which are causes for concern for the Company. As these technologies become more economically attractive for customers, customers may reduce their reliance on, and in some cases may disconnect from, the system, which could put the Company at risk of lost revenues and possible stranded assets.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING SDG&E'S COST OF COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses, the application of my professional judgment, and the rather extraordinary risk circumstances of SDG&E, it is my opinion that a barebones ROE for SDG&E's jurisdictional electric transmission operations is 11.2%.

Q. IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED DIRECT TESTIMONY AND THE DATE ORAL TESTIMONY IS PRESENTED,

WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

Dr. Roger A. Morin hereby declares under penalty of perjury of the laws of the United States that the foregoing document is true and correct to the best of his knowledge and belief. See 28 U.S.C. § 1746.

Executed this 25th day of October, 2018

Roger A. Morin

_______________________________-

EXHIBIT NO. SD-0020

TO THE PREPARED DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

RESUME OF ROGER A. MORIN

(Winter 2017)

NAME: Roger A. Morin

ADDRESS: 9 King Ave.
Jekyll Island, GA 31527, USA

132 Paddys Head Rd
Indian Harbour
Nova Scotia, Canada B3Z 3N8

TELEPHONE: (912) 635-2920 business office
(404) 229-2857 cellular
(902) 823-0000 summer office

E-MAIL ADDRESS: profmorin@mac.com

EMPLOYER 1980-2015: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: Distinguished Professor of Finance for Regulated Industry,
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3

- Assistant Professor, University of Montreal School of Business, 1973-1976.

- Associate Professor, University of Montreal School of Business, 1976-1979.

- Professor of Finance, Georgia State University, 1979-2011

- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

- Emeritus Professor of Finance, Georgia State University, 2007-16

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.

- Member Board of Directors, Financial Research Institute of Canada, 1974-1980.

- Co-founder and Director Canadian Finance Research Foundation, 1977.

- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.

- Member Board of Directors, Executive Visions Inc., 1985-2016

- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.

- Member Board of Directors, Hotel Equities Inc., 2009-2016

PROFESSIONAL CLIENTS

AGL Resources
AT & T Communications
Alagasco - Energen
Alaska Anchorage Municipal Light & Power
Alberta Power Ltd.
Allete
Alliant Energy
AmerenUE
American Water
Ameritech
Arkansas Western Gas
ATC Transmission
Baltimore Gas & Electric – Constellation Energy
Bangor Hydro-Electric
B.C. Telephone
B C GAS
Bell Canada
Bellcore
Bell South Corp.
Bruncor (New Brunswick Telephone)

Burlington-Northern
C & S Bank
California Pacific
Cajun Electric
Canadian Radio-Television & Telecomm. Commission
Canadian Utilities
Canadian Western Natural Gas
Cascade Natural Gas
Centel
Centra Gas
Central Illinois Light & Power Co
Central Telephone
Central & South West Corp.
CH Energy
Chattanooga Gas Company
Cincinnatti Gas & Electric
Cinergy Corp.
Citizens Utilities
City Gas of Florida
CN-CP Telecommunications
Commonwealth Telephone Co.
Columbia Gas System
Consolidated Edison
Consolidated Natural Gas
Constellation Energy
Delmarva Power & Light Co
Deerpath Group
Detroit Edison Company
Dayton Power & Light Co.
DPL Energy
Duke Energy Indiana
Duke Energy Kentucky
Duke Energy Ohio
DTE Energy
Edison International
Edmonton Power Company
Elizabethtown Gas Co.
Emera
Energen
Engraph Corporation
Entergy Corp.
Entergy Arkansas Inc.
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi Power
Entergy New Orleans, Inc.

First Energy
Florida Water Association
Fortis
Garmaise-Thomson & Assoc., Investment Consultants
Gaz Metropolitain
General Public Utilities
Georgia Broadcasting Corp.
Georgia Power Company
GTE California - Verizon
GTE Northwest Inc. - Verizon
GTE Service Corp. - Verizon
GTE Southwest Incorporated - Verizon
Gulf Power Company
Havasu Water Inc.
Hawaiian Electric Company
Hawaiian Elec & Light Co
Heater Utilities – Aqua - America
Hope Gas Inc.
Hydro-Quebec
ICG Utilities
Illinois Commerce Commission
Island Telephone
ITC Holdings
Jersey Central Power & Light
Kansas Power & Light
KeySpan Energy
Maine Public Service
Manitoba Hydro
Maritime Telephone
Maui Electric Co.
Metropolitan Edison Co.
Minister of Natural Resources Province of Quebec
Minnesota Power & Light
Mississippi Power Company
Missouri Gas Energy
Mountain Bell
National Grid PLC
Nevada Power Company
New Brunswick Power
Newfoundland Power Inc. - Fortis Inc.
New Market Hydro
New Tel Enterprises Ltd.
New York Telephone Co.
NextEra Energy
Niagara Mohawk Power Corp
Norfolk-Southern

Northeast Utilities
Northern Telephone Ltd.
Northwestern Bell
Northwestern Utilities Ltd.
Nova Scotia Power
Nova Scotia Utility and Review Board
NUI Corp.
NV Energy
NYNEX
Oklahoma G & E
Ontario Telephone Service Commission
Orange & Rockland
PNM Resources
PPL Corp
Pacific Northwest Bell
People's Gas System Inc.
People's Natural Gas
Pennsylvania Electric Co.
Pepco Holdings
Potomac Electric Power Co.
Price Waterhouse
PSI Energy
Public Service Electric & Gas
Public Service of New Hampshire
Public Service of New Mexico
Puget Sound Energy
Quebec Telephone
Regie de l'Energie du Quebec
Rockland Electric
Rochester Telephone
SNL Center for Financial Execution
San Diego Gas & Electric
SaskPower
Sempra
Sierra Pacific Power Company
Source Gas
Southern Bell
Southern States Utilities
Southern Union Gas
South Central Bell
Sun City Water Company
TECO Energy
The Southern Company
Touche Ross and Company
TransEnergie
Trans-Quebec & Maritimes Pipeline

TXU Corp
US WEST Communications
Union Heat Light & Power
Utah Power & Light
Vermont Gas Systems Inc.
Wisconsin Power & Light

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73

- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75

- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78

- Investment Dealers Association of Canada, 1977-78

- Financial Research Foundation, bi-annual seminar, 1975-79

- Advanced Management Research (AMR), faculty member, 1977-80

- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar

- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2008:

  National Seminars: *Risk and Return on Capital Projects*
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Fundamentals of Utility Finance
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education. faculty member 2008-2016.
  National Seminars: *Essentials of Utility Finance*

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994.

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance
Rate of Return
Capital Structure
Generic Cost of Capital
Costing Methodology
Depreciation
Flow-Through vs Normalization

Revenue Requirements Methodology
Utility Capital Expenditures Analysis
Risk Analysis
Capital Allocation
Divisional Cost of Capital, Unbundling
Incentive Regulation & Alternative Regulatory Plans
Shareholder Value Creation
Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission
Alaska Regulatory Commission
Alberta Public Service Board
Arizona Corporation Commission
Arkansas Public Service Commission
British Columbia Board of Public Utilities
California Public Service Commission
Canadian Radio-Television & Telecommunications Comm.
City of New Orleans Council
Colorado Public Utilities Commission
Delaware Public Service Commission
District of Columbia Public Service Commission
Federal Communications Commission
Federal Energy Regulatory Commission
Florida Public Service Commission
Georgia Public Service Commission
Georgia Senate Committee on Regulated Industries
Hawaii Public Utilities Commission
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Louisiana Public Service Commission
Maine Public Utilities Commission
Manitoba Board of Public Utilities
Maryland Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Mississippi Public Service Commission
Missouri Public Service Commission
Montana Public Service Commission
National Energy Board of Canada
Nebraska Public Service Commission
Nevada Public Utilities Commission
New Brunswick Board of Public Commissioners
New Hampshire Public Utilities Commission

New Jersey Board of Public Utilities
New Mexico Public Regulation Commission
New Orleans City Council
New York Public Service Commission
Newfoundland Board of Commissioners of Public Utilities
North Carolina Utilities Commission
Nova Scotia Board of Public Utilities
Ohio Public Utilities Commission
Oklahoma Corporation Commission
Ontario Telephone Service Commission
Ontario Energy Board
Oregon Public Utility Service Commission
Pennsylvania Public Utility Commission
Quebec Regie de l'Energie
Quebec Telephone Service Commission
South Carolina Public Service Commission
South Dakota Public Utilities Commission
Tennessee Regulatory Authority
Texas Public Utility Commission
Utah Public Service Commission
Vermont Department of Public Services
Virginia State Corporation Commission
Washington Utilities & Transportation Commission
West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C
Southern Bell, So. Carolina PSC, Docket #82-294C
Southern Bell, North Carolina PSC, Docket #P-55-816
Metropolitan Edison, Pennsylvania PUC, Docket #R-822249
Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250
Georgia Power, Georgia PSC, Docket # 3270-U, 1981
Georgia Power, Georgia PSC, Docket # 3397-U, 1983
Georgia Power, Georgia PSC, Docket # 3673-U, 1987
Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327
Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731
Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731
Bell Canada, CRTC 1987
Northern Telephone, Ontario PSC
GTE-Quebec Telephone, Quebec PSC, Docket 84-052B
Newtel., Nfld. Brd of Public Commission PU 11-87
CN-CP Telecommunications, CRTC
Quebec Northern Telephone, Quebec PSC
Edmonton Power Company, Alberta Public Service Board
Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800
Bell South, FCC generic cost of capital Docket #84-800
American Water Works - Tennessee, Docket #7226
Burlington-Northern - Oklahoma State Board of Taxes
Georgia Power, Georgia PSC, Docket # 3549-U
GTE Service Corp., FCC Docket #84-200
Mississippi Power Co., Miss. PSC, Docket U-4761
Citizens Utilities, Ariz. Corp. Comm., Docket U2334-86020
Quebec Telephone, Quebec PSC, 1986, 1987, 1992
Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991
Northwestern Bell, Minnesota PSC, Docket P-421/CI-86-354
GTE Service Corp., FCC Docket #87-463
Anchorage Municipal Power & Light, Alaska PUC, 1988
New Brunswick Telephone, N.B. PUC, 1988
Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92
Gulf Power Co., Florida PSC, Docket #88-1167-EI
Mountain States Bell, Montana PSC, #88-1.2
Mountain States Bell, Arizona CC, #E-1051-88-146
Georgia Power, Georgia PSC, Docket # 3840-U, I989
Rochester Telephone, New York PSC, Docket # 89-C-022
Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89
GTE Northwest, Washington UTC, #U-89-3031
Orange & Rockland, New York PSC, Case 89-E-175
Central Illinois Light Company, ICC, Case 90-0127
Peoples Natural Gas, Pennsylvania PSC, Case
Gulf Power, Florida PSC, Case # 891345-EI
ICG Utilities, Manitoba BPU, Case 1989
New Tel Enterprises, CRTC, Docket #90-15
Peoples Gas Systems, Florida PSC
Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J
Alabama Gas Co., Alabama PSC, Case 890001
Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board
Mountain Bell, Utah PSC,
Mountain Bell, Colorado PUB
South Central Bell, Louisiana PS
Hope Gas, West Virginia PSC
Vermont Gas Systems, Vermont PSC
Alberta Power Ltd., Alberta PUB
Ohio Utilities Company, Ohio PSC
Georgia Power Company, Georgia PSC
Sun City Water Company
Havasu Water Inc.
Centra Gas (Manitoba) Co.
Central Telephone Co. Nevada
AGT Ltd., CRTC 1992
BC GAS, BCPUB 1992

California Water Association, California PUC 1992
Maritime Telephone 1993
BCE Enterprises, Bell Canada, 1993
Citizens Utilities Arizona gas division 1993
PSI Resources 1993-5
CILCORP gas division 1994
GTE Northwest Oregon 1993
Stentor Group 1994-5
Bell Canada 1994-1995
PSI Energy 1993, 1994, 1995, 1999
Cincinnati Gas & Electric 1994, 1996, 1999, 2004
Southern States Utilities, 1995
CILCO 1995, 1999, 2001
Commonwealth Telephone 1996
Edison International 1996, 1998
Citizens Utilities 1997
Stentor Companies 1997
Hydro-Quebec 1998
Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003
Detroit Edison, 1999, 2003
Entergy Gulf States, Texas, 2000, 2004
Hydro Quebec TransEnergie, 2001, 2004
Sierra Pacific Company, 2000, 2001, 2002, 2007, 2010
Nevada Power Company, 2001
Mid American Energy, 2001, 2002
Entergy Louisiana Inc. 2001, 2002, 2004
Mississippi Power Company, 2001, 2002, 2007
Oklahoma Gas & Electric Company, 2002 -2003
Public Service Electric & Gas, 2001, 2002
NUI Corp (Elizabethtown Gas Company), 2002
Jersey Central Power & Light, 2002
San Diego Gas & Electric, 2002, 2012, 2014
New Brunswick Power, 2002
Entergy New Orleans, 2002, 2008
Hydro-Quebec Distribution 2002
PSI Energy 2003
Fortis – Newfoundland Power & Light 2002
Emera – Nova Scotia Power 2004
Hydro-Quebec TransEnergie 2004
Hawaiian Electric 2004
Missouri Gas Energy 2004
AGL Resources 2004
Arkansas Western Gas 2004
Public Service of New Hampshire 2005
Hawaiian Electric Company 2005, 2008, 2009
Delmarva Power & Light Company 2005, 2009

Union Heat Power & Light 2005
Puget Sound Energy 2006, 2007, 2009
Cascade Natural Gas 2006
Entergy Arkansas 2006-7
Bangor Hydro 2006-7
Delmarva 2006, 2007, 2009
Potomac Electric Power Co. 2006, 2007, 2009
Duke Energy Ohio, 2007, 2008, 2009
Duke Energy Kentucky 2009
Consolidated Edison 2007 Docket 07-E-0523
Duke Energy Ohio Docket 07-589-GA-AIR
Hawaiian Electric Company Docket 05-0315
Sierra Pacific Power Docket ER07-1371-000
Public Service New Mexico Docket 06-00210-UT
Detroit Edison Docket U-15244
Potomac Electric Power Docket FC-1053
Delmarva, Delaware, Docket 09-414
Atlantic City Electric, New Jersey, Docket ER-09080664
Maui Electric Co, Hawaii, Docket 2009-0163, 2011
Niagara Mohawk, New York, Docket 10E-0050
Sierra Pacific Power Docket No. 10-06001
Gaz Metro, Regie de l'Energie (Quebec), Docket 2012 R-3752-2011
California Pacific Electric Company, LLC, California PUC, Docket A-12-02-014
Duke Energy Ohio, Ohio Case No. 11-XXXX-EL-SSO
San Diego Gas & Electric, FERC, 2012, 2014
San Diego Gas & Electric, California PUC, 2012, Docket A-12-04
Southern California Gas, California PUC, 2012, Docket A-12-04
Puget Sound Electric
Puget Sound Electric
Duke Energy of Ohio
Duke Energy of Kentucky
Duke Energy of Ohio
Dayton Power & Light
Missouri American Water
California Power Electric Company

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fl, 1988.

- Guest speaker, "Mythodology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, l978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977
- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975
- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976
- Member, New Product Development Committee, Financial Management Association, 1985-1986
- Reviewer: Journal of Financial Research
  Financial Management
  Financial Review
  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. l982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

“An Economic & Financial Profile of the Canadian Cablevision Industry,” Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

“Operational Risk Analysis: California Water Utilities,” Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique," CRTC, 1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry," International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities," Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

EXHIBIT NO. SD-0021

TO THE PREPARED DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

Investment-Grade Dividend-Paying Combination Gas and Electric Utilities Covered in Value Line's Electric Utility

	(1) Company	(2) Ticker	(3)	(4) Note
1	Alliant Energy	LNT		
2	Ameren Corp.	AEE		
3	Avista Corp.	AVA	x	Acquidition of Hydro One
4	Black Hills	BKH		Acquired SourceGas, completed 2/2016
5	CenterPoint Energy	CNP	x	Acquiring Vectren
6	Chesapeake Utilities	CPK		
7	CMS Energy Corp.	CMS		
8	Consol. Edison	ED		
9	Dominion Resources	D		Merged with Questar, completed 9/16
10	DTE Energy	DTE		
11	Duke Energy	DUK		Acquired Piedmont Natual Gas, completed 10/1
12	Empire Dist. Elec.	EDE	x	Merged with Liberty Utility, completed 1/17
13	Entergy Corp	ETR	x	Nuclear exposure, corporate reorganization
14	Eversource Energy	ES		
15	Fortis	FTS		Owns several US combination gas & elec utiliti
16	Exelon Corp	EXC		
17	MDU Resource	MDU	x	Reg. Revenues < 50%
18	MGE Energy	MGEE		
19	NorthWestern Corp.	NWE		
20	Pepco Holdings	POM	x	Merged with Exelon
21	PG&E Corp.	PCG	x	Suspended dividends
22	Public Serv. Enterprise	PEG		
23	SCANA Corp.	SCG	x	nuclear exposure, writeoffs, dividend cut
24	Unitil Corp	UTL	x	Market cap < $1B; not covered by VL
25	Sempra Energy	SRE		Acquisition of Oncor completed 3/18
26	TECO Energy	TE	x	Acquired by Emera
27	Vectren Corp.	VVC	x	Acquired by CenterPoint
28	WEC Energy Group	WEC		
29	Xcel Energy Inc.	XEL		

Source: Value Line Investment Survey 09/18

EXHIBIT NO. SD-0022

TO THE PREPARED DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

Exhibit No. SD-0022

Proxy Group for SDG&E

	Company	Ticker
1	Alliant Energy	LNT
2	Ameren Corp.	AEE
3	Black Hills	BKH
4	Chesapeake Utilities	CPK
5	CMS Energy Corp.	CMS
6	Consol. Edison	ED
7	Dominion Resources	D
8	DTE Energy	DTE
9	Duke Energy	DUK
10	Eversource Energy	ES
11	Exelon Corp	EXC
12	Fortis	FTS
13	MGE Energy	MGEE
14	NorthWestern Corp.	NWE
15	Public Serv. Enterprise	PEG
16	Sempra	SRE
17	WEC Energy Group	WEC
18	Xcel Energy Inc.	XEL

EXHIBIT NO. SD-0023

TO THE PREPARED DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

Exhibit No. SD-0023

Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.1	6.5	3.32	9.82	10.00
2	Ameren Corp.	2.9	7.5	3.10	10.60	10.76
3	Black Hills	3.2	6.5	3.41	9.91	10.09
4	Chesapeake Utilities	1.7	8.5	1.88	10.38	10.48
5	CMS Energy Corp.	2.9	7.0	3.09	10.09	10.26
6	Consol. Edison	3.6	3.0	3.71	6.71	6.90
7	Dominion Resources	4.7	6.5	5.02	11.52	11.78
8	DTE Energy	3.2	7.0	3.38	10.38	10.56
9	Duke Energy	4.6	5.5	4.81	10.31	10.56
10	Eversource Energy	3.2	5.0	3.38	8.38	8.56
11	Exelon Corp	3.1	8.0	3.39	11.39	11.57
12	Fortis	4.0	8.0	4.29	12.29	12.51
13	MGE Energy	2.1	7.5	2.21	9.71	9.83
14	NorthWestern Corp.	3.7	3.5	3.78	7.28	7.48
15	Public Serv. Enterprise	3.4	4.0	3.58	7.58	7.77
16	**Sempra**	**3.1**	**9.5**	**3.36**	**12.86**	**13.04**
17	WEC Energy Group	3.3	7.0	3.49	10.49	10.67
18	Xcel Energy Inc.	3.1	5.5	3.31	8.81	8.99
21	**AVERAGE**	**3.27**	**6.44**	**3.47**	**9.92**	**10.10**

Notes:

24 Column 2: Zacks Investment Research Sep 2018

25 Column 3: Value Line Investment Reports Sep 2018

26 Column 4 = Column 2 times (1 + Column 3/100)

27 Column 5 = Column 4 + Column 3

28 Column 6 = Column 4/0.95 + Column 3

EXHIBIT NO. SD-0024

TO THE PREPARED DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

Exhibit No. SD-0024

Combination Elec & Gas Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.1	5.5	3.27	8.77	8.94
2	Ameren Corp.	2.9	6.6	3.09	9.69	9.85
3	Black Hills	3.2	4.5	3.34	7.84	8.02
4	Chesapeake Utilities	1.7	6.0	1.80	7.80	7.90
5	CMS Energy Corp.	2.9	6.2	3.08	9.28	9.44
6	Consol. Edison	3.6	3.0	3.71	6.71	6.90
7	Dominion Resources	4.7	6.1	4.99	11.09	11.35
8	DTE Energy	3.2	5.3	3.37	8.67	8.85
9	Duke Energy	4.6	4.6	4.81	9.41	9.66
10	Eversource Energy	3.2	5.9	3.39	9.29	9.47
11	Exelon Corp	3.1	5.7	3.28	8.98	9.15
12	Fortis	4.0	5.5	4.22	9.72	9.94
13	MGE Energy	2.1	7.5	2.26	9.76	9.88
14	NorthWestern Corp.	3.7	2.3	3.79	6.09	6.28
15	Public Serv. Enterprise	3.4	6.0	3.60	9.60	9.79
16	**Sempra**	**3.1**	**8.0**	**3.35**	**11.35**	**11.52**
17	WEC Energy Group	3.3	4.1	3.44	7.54	7.72
18	Xcel Energy Inc.	3.1	5.8	3.28	9.08	9.25
21	**AVERAGE**	**3.27**	**5.48**	**3.45**	**8.93**	**9.11**

Notes:

24 Column 2, 3: Zacks Investment Research Sep 2018

25 Column 4 = Column 2 times (1 + Column 3/100)

26 Column 5 = Column 4 + Column 3

27 Column 6 = Column 4/0.95 + Column 3

EXHIBIT NO. SD-0025

TO THE PREPARED DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

Exhibit No. SD-0025

Combination Elec & Gas Utilities Beta Estimates

	(1)	(2)
Line No.	Company Name	Beta
1	Alliant Energy	0.70
2	Ameren Corp.	0.65
3	Black Hills	0.85
4	Chesapeake Utilities	0.70
5	CMS Energy Corp.	0.65
6	Consol. Edison	0.45
7	Dominion Resources	0.60
8	DTE Energy	0.65
9	Duke Energy	0.55
10	Eversource Energy	0.60
11	Exelon Corp	0.65
12	Fortis	0.70
13	MGE Energy	0.70
14	NorthWestern Corp.	0.65
15	Public Serv. Enterprise	0.65
16	**Sempra**	**0.75**
17	WEC Energy Group	0.60
18	Xcel Energy Inc.	0.60
25	**AVERAGE**	**0.65**
27	Source: Value Line Reports Sep 2018	

EXHIBIT NO. SD-0026

TO THE PREPARED DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

2018 Utility Industry Historical Risk Premium

		(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No	Year	Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
1	1931	4.07%	3.33%	1,000.00						
2	1932	3.15%	3.69%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%	-4.23%
3	1933	3.36%	3.12%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%	-24.99%
4	1934	2.93%	3.10%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%	-23.51%
5	1935	2.76%	2.81%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%	73.82%
6	1936	2.56%	2.77%	1,031.15	31.15	27.60	5.88%	20.69%	14.81%	17.92%
7	1937	2.73%	2.66%	973.93	-26.07	25.60	-0.05%	-37.04%	-36.99%	-39.70%
8	1938	2.52%	2.64%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%	19.81%
9	1939	2.26%	2.40%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%	8.86%
10	1940	1.94%	2.23%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%	-19.38%
11	1941	2.04%	1.94%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%	-33.51%
12	1942	2.46%	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%	12.93%
13	1943	2.48%	2.44%	996.86	-3.14	24.60	2.15%	46.07%	43.92%	43.63%
14	1944	2.46%	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%	15.57%
15	1945	1.99%	2.34%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%	50.99%
16	1946	2.12%	2.04%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%	-0.78%
17	1947	2.43%	2.13%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%	-15.29%
18	1948	2.37%	2.40%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%	1.61%
19	1949	2.09%	2.25%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%	29.14%
20	1950	2.24%	2.12%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%	1.13%
21	1951	2.69%	2.38%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%	16.25%
22	1952	2.79%	2.68%	984.75	-15.25	26.90	1.17%	19.25%	18.08%	16.57%
23	1953	2.74%	2.84%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%	5.01%
24	1954	2.72%	2.79%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%	21.93%
25	1955	2.95%	2.75%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%	8.51%
26	1956	3.45%	2.99%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%	2.07%
27	1957	3.23%	3.44%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%	2.92%
28	1958	3.82%	3.27%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%	37.43%
29	1959	4.47%	4.01%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%	3.48%
30	1960	3.80%	4.26%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%	16.00%
31	1961	4.15%	3.83%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%	25.50%
32	1962	3.95%	4.00%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%	-6.44%
33	1963	4.17%	3.89%	970.35	-29.65	39.50	0.99%	12.36%	11.37%	8.47%
34	1964	4.23%	4.15%	991.96	-8.04	41.70	3.37%	15.91%	12.54%	11.76%
35	1965	4.50%	4.20%	964.64	-35.36	42.30	0.69%	4.67%	3.98%	0.47%
36	1966	4.55%	4.49%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%	-8.97%
37	1967	5.56%	4.59%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%	-5.22%
38	1968	5.98%	5.50%	951.38	-48.62	55.60	0.70%	10.32%	9.62%	4.82%
39	1969	6.87%	5.96%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%	-21.38%
40	1970	6.48%	6.74%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%	9.82%
41	1971	5.97%	6.32%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%	-3.91%

42	1972	5.99%	5.87%	997.69	-2.31	59.70	5.74%	8.15%	2.41%	2.28%
43	1973	7.26%	6.51%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%	-24.58%
44	1974	7.60%	7.27%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%	-28.82%
45	1975	8.05%	7.99%	955.63	-44.37	76.00	3.16%	44.49%	41.33%	36.50%
46	1976	7.21%	4.89%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%	26.92%
47	1977	8.03%	7.14%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%	1.50%
48	1978	8.98%	7.90%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%	-11.61%
49	1979	10.12%	8.86%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%	4.72%
50	1980	11.99%	9.97%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%	5.11%
51	1981	13.34%	11.55%	906.45	-93.55	119.90	2.63%	11.74%	9.11%	0.19%
52	1982	10.95%	13.50%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%	13.02%
53	1983	11.97%	10.38%	923.12	-76.88	109.50	3.26%	20.01%	16.75%	9.63%
54	1984	11.70%	11.74%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%	14.30%
55	1985	9.56%	11.25%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%	21.80%
56	1986	7.89%	8.98%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%	19.55%
57	1987	9.20%	7.92%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%	-10.84%
58	1988	9.19%	8.97%	1,000.91	0.91	92.00	9.29%	18.27%	8.98%	9.30%
59	1989	8.16%	8.10%	1,100.73	100.73	91.90	19.26%	47.80%	28.54%	39.70%
60	1990	8.44%	8.19%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%	-10.76%
61	1991	7.30%	8.22%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%	6.39%
62	1992	7.26%	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%	0.84%
63	1993	6.54%	7.17%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%	7.24%
64	1994	7.99%	6.59%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%	-14.53%
65	1995	6.03%	7.60%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%	34.55%
66	1996	6.73%	6.18%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%	-3.04%
67	1997	6.02%	6.64%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%	18.05%
68	1998	5.42%	5.83%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%	8.99%
69	1999	6.82%	5.57%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%	-14.42%
70	2000	5.58%	6.50%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%	53.20%
71	2001	5.75%	5.53%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%	-35.94%
72	2002	4.84%	5.59%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%	-35.63%
73	2003	5.11%	4.80%	966.42	-33.58	48.40	1.48%	26.11%	24.63%	21.31%
74	2004	4.84%	5.02%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%	19.20%
75	2005	4.61%	4.69%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%	12.10%
76	2006	4.91%	4.68%	962.06	-37.94	46.10	0.82%	20.95%	20.13%	16.27%
77	2007	4.50%	4.86%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%	14.50%
78	2008	3.03%	4.45%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%	-33.44%
79	2009	4.58%	3.47%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%	8.47%
80	2010	4.14%	4.25%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%	1.24%
81	2011	2.48%	3.81%	1,260.50	260.50	41.40	30.19%	19.88%	-10.31%	16.07%
82	2012	2.41%	2.40%	1,011.06	11.06	24.80	3.59%	1.99%	-1.60%	-0.41%
83	2013	3.67%	2.86%	822.57	-177.43	24.10	-15.33%	13.26%	28.59%	10.40%
84	2014	2.40%	3.12%	1,200.79	200.79	36.70	23.75%	28.61%	4.86%	25.49%
85	2015	2.60%	2.84%	968.96	-31.04	24.00	-0.70%	1.38%	2.08%	-1.46%
86	2016	2.60%	2.63%	1,000.00	0.00	26.00	2.60%	11.93%	9.33%	9.30%
87	2017	2.90%	2.89%	954.71	-45.29	26.00	-1.93%	12.11%	14.04%	9.22%
89	**Mean**								**5.6%**	**6.2%**

91 Source Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Jan. to Dec.
92 Bond yields from Duff & Phelps Classic Yearbooks Table A-9 Long-Term Government Bonds Yields
93 and Fed Reserve H-15 Data Release

EXHIBIT NO. SD-0027

TO THE PREPARED DIRECT TESTIMONY OF

ROGER A. MORIN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

OCTOBER 30, 2018

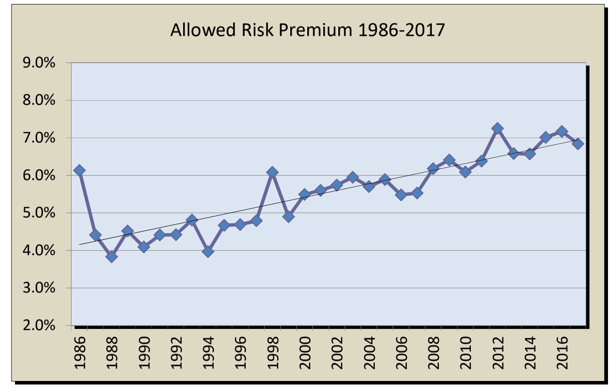
Equity Risk Premium - Treasury Bond

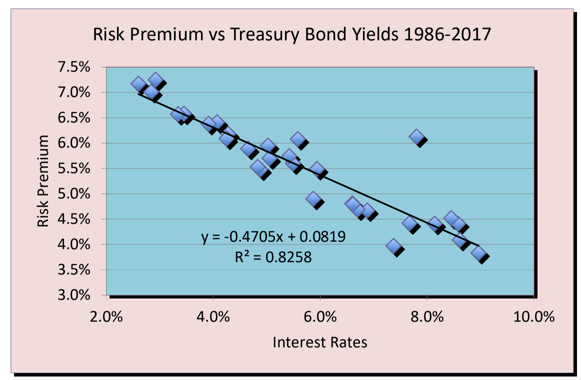
Line	Date	Treasury Bond Yield[1]	Authorized Electric Returns[2]	Indicated Risk Premium
		(1)	(2)	(3)
1	1986	7.80%	13.93%	6.1%
2	1987	8.58%	12.99%	4.4%
3	1988	8.96%	12.79%	3.8%
4	1989	8.45%	12.97%	4.5%
5	1990	8.61%	12.70%	4.1%
6	1991	8.14%	12.55%	4.4%
7	1992	7.67%	12.09%	4.4%
8	1993	6.60%	11.41%	4.8%
9	1994	7.37%	11.34%	4.0%
10	1995	6.88%	11.55%	4.7%
11	1996	6.70%	11.39%	4.7%
12	1997	6.61%	11.40%	4.8%
13	1998	5.58%	11.66%	6.1%
14	1999	5.87%	10.77%	4.9%
15	2000	5.94%	11.43%	5.5%
16	2001	5.49%	11.09%	5.6%
17	2002	5.42%	11.16%	5.7%
18	2003	5.02%	10.97%	6.0%
19	2004	5.05%	10.75%	5.7%
20	2005	4.65%	10.54%	5.9%
21	2006	4.88%	10.36%	5.5%
22	2007	4.83%	10.36%	5.5%
23	2008	4.28%	10.46%	6.2%
24	2009	4.07%	10.48%	6.4%
25	2010	4.25%	10.34%	6.1%
26	2011	3.91%	10.29%	6.4%
27	2012	2.92%	10.17%	7.3%
28	2013	3.45%	10.03%	6.6%
29	2014	3.34%	9.91%	6.6%
30	2015	2.84%	9.85%	7.0%
31	2016	2.60%	9.77%	7.2%
32	2017	2.90%	9.74%	6.8%
34	**Average**	**5.61%**	**11.16%**	**5.55%**

Sources:

1 Fed Reserve Board of Governors H.15 Release, 30-Yr Treasury rate

2 S&P Global Intelligence (Regulatory Research Associates) *Major Rate Case Decisions 1986-2017*





IF YIELD =	4.30%
THEN RP =	6.17%
Ke =	10.47%

Exhibit No. SD-0028

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER19-__-000

PREPARED DIRECT TESTIMONY OF

DON WIDJAJA

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

October 30, 2018

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF
DON WIDJAJA
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Don Widjaja. I am the Director of Financial Planning and Regulatory Accounts for San Diego Gas & Electric Company ("SDG&E"). My business address is 8330 Century Park Court, San Diego CA, 92123

Q. Please describe your current responsibilities.

A. My current responsibilities include the development, implementation, and analysis of SDG&E's financial planning and budget process, as well as overseeing the development, analysis, and implementation of financing strategies, revenue requirements, regulatory accounts, and cost recovery mechanisms.

Q. Please describe your educational and professional background.

A. I hold a Master of Business Administration degree from Washington University in St. Louis with an emphasis in finance. I received a Bachelor of Science degree in Chemical Engineering from Purdue University.

In 2008, I joined SDG&E as the Quantitative Risk and Controls Manager in the Risk Management Department, where I was responsible for providing risk assessment on energy procurement activities, major projects, and new business initiatives. Prior to joining SDG&E, I worked at Credit Suisse and Ameren Corporation.

Q. Have you previously testified before this Commission?

A. No.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony, and how is it organized?

A. The purpose of my testimony is to provide an overview of the investment risk that should be considered in determining SDG&E's overall return on common equity ("ROE"). SDG&E's proposed ROE is discussed in the testimony of SDG&E witness Dr. Roger Morin.[1] I explain SDG&E's risk profile in the following three areas: (1) Business Risks; (2) Financial Risks; and (3) Regulatory Risks. These risks inform Dr. Morin's analysis of SDG&E's ROE.

Q. Why is risk an important component in assessing SDG&E's ROE?

A. Capital markets determine the price of investor capital (*i.e.*, the required return on stocks and bonds) based on the riskiness of the borrower in relation to other borrowers. Investors have many investment choices, including stocks, bonds, money funds, treasury securities, and real estate. In order for SDG&E to attract the necessary funds, it must offer potential investors the prospect of earning a return on their investment that is equal to the potential returns offered by other investments of comparable risk.

Q. How is your testimony organized?

I have organized my testimony as follows:

I. Introduction

II. Purpose of Testimony

III. Business Risks

---

[1] In addition, SDG&E witness Bruce Folkmann provides support for SDG&E's proposed 50 basis-point adder to compensate it for its membership in the California Independent System Operator Corporation.

IV. Financial Risks

V. Regulatory Risks

III. BUSINESS RISKS

Q. Please describe business risk.

A. Business risk is the exposure of investors' anticipated returns to the uncertainties of a company's day-to-day business activities. A company's business risk profile is essentially a qualitative assessment of the economic and business environment in which the company operates.

Q. What are the business risks that SDG&E faces?

A. SDG&E significant business risks, both in the present and the future attributable to, among other things, the following circumstances:

- Catastrophic wildfires;
- Changes in the California energy industry.

I discuss each of these risks below.

A. Catastrophic Wildfires

Q. Please describe the business risk associated with catastrophic wildfires.

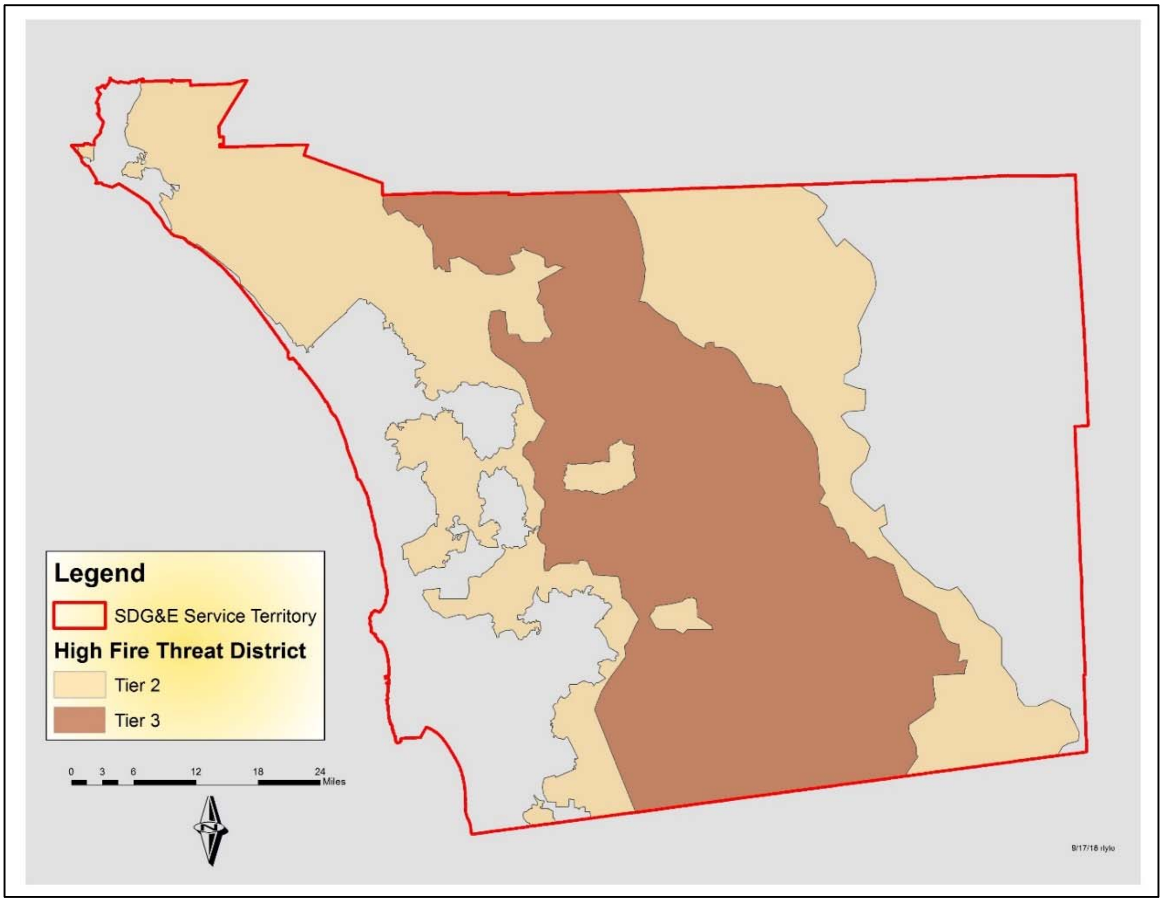
A. At a high level, the business risk associated with catastrophic wildfires comprises two related elements: (1) the frequency of catastrophic wildfires in California; and (2) the potential that SDG&E may face massive uninsured, and unrecoverable liabilities if its equipment is involved in a wildfire ignition.

Q. Please elaborate.

A. SDG&E's service territory includes San Diego County and parts of Orange County, a region that is extremely prone to wildfire outbreaks. As depicted in

Figure 1 below, 57% of SDG&E's service territory is classified as High Fire Threat District by the California Public Utilities Commission ("CPUC").

Figure 1: SDG&E Service Territory and High Fire Threat District Boundaries



In the past, SDG&E powerlines have been a source of wildfire ignitions, and such wildfires can spread quickly and cause extreme damage due to the presence of dry, gusty Santa Ana winds and dry vegetation in a region that sees very little annual rainfall. The California Department of Forestry and Fire Protection ("Cal Fire") attributed three of the many wildfires that ignited the October 2007 firestorm to SDG&E powerlines.

Under California state law, utilities are strictly liable for property damage caused by utility facilities under the doctrine of inverse condemnation, even in the absence of fault and where the utility facilities were one of several concurrent causes.[2] In the aftermath of the October 2007 wildfires, SDG&E settled approximately 2,500 claims, paying approximately $2.4 billion. While SDG&E was able to recover a portion of those settlement costs through insurance ($1.1 billion), recoveries from third parties ($827 million), and FERC-authorized recoveries ($80 million),[3] the CPUC denied all recovery of the state portion of the 2007 wildfire costs, totaling $421 million,[4] in December 2017. The losses were incurred primarily because California courts apply inverse condemnation on the rationale that the public entity or utility can spread costs through rates. Thus, SDG&E faces a substantial risk of major legal and defense costs that it may be unable to recover in rates.

From an equity investor's perspective, having these 2007 wildfire costs stranded for over 10 years with no cost recovery represents an annual risk of $42 million pre-tax or $30 million after-tax.[5] Given this elevated level of risk, I

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[2] *See Barham v. Southern California Edison Co.*, 74 Cal. App. 4th 744, 752 (1999) ("The fundamental policy underlying the concept of inverse condemnation is to spread among the benefiting community any burden disproportionately borne by a member of that community, to establish a public undertaking for the benefit of all.")

[3] *See, e.g., San Diego Gas & Electric Co.*, 146 FERC ¶ 63,017 (2014) (this initial decision became the final decision of the Commission by operation of law because no exceptions were taken to it).

[4] *See* CPUC Decision 17-11-033. The total state portion of the 2007 wildfire costs was $421 million. After applying a voluntary 10% shareholder contribution to this amount, SDG&E requested $379 million in CPUC cost recovery. SDG&E has filed a petition for writ of review of CPUC Decision 17-11-033 with the California Court of Appeal.

[5] Statutory Tax Rate of 28% is comprised of both Federal and California State tax rates.

believe that equity investors would require a premium on ROE of 35 basis points as calculated in Table 1 below.

Table 1: ROE Premium derived from 2007 wildfires losses.

$ in millions		Calculations
Unrecovered 2007 Wildfire cost	$421	(1)
After-tax loss @ 28% Tax Rate	$303	(2) = (1) – [28% x (1)]
Annual after-tax loss over 10 years	$30.3	(3) = (2) / 10
2017 Weighted Average Ratebase	$8,549 [6]	(4)
Return on Equity (ROE) Premium	0.35%	(5) = (3) / (4)

Furthermore, the 2007 wildfires were not isolated occurrences. SDG&E's service territory has experienced several other significant wildfire events since 2007, including the Bernardo, Cocos and Poinsettia fires in May 2014, the Lilac Fire in December 2017, and the West Fire in June 2018, among others, although those fires were not linked to SDG&E equipment.

Recent events in other parts of California further illustrate the major risk for utilities posed by catastrophic wildfires in the state. In October 2017, Northern California experienced more than 170 wildfires, burning at least 245,000 acres.[7] Cal Fire issued a News Release on June 8, 2018 in which its investigators announced that 12 wildfires across several Northern California counties were caused by Pacific Gas & Electric Company's ("PG&E") equipment.[8] As of the

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6 *See* Sempra Energy 2017 Form 10-K, Page 74.

7 *See* "CAL FIRE Investigators Determine Cause of Four Wildfires in Butte and Nevada Counties," News Release issued by Cal Fire, May 25, 2018, available at https://calfire.ca.gov/communications/downloads/newsreleases/2018/2017_WildfireSiege_Cause%20v2%20AB%20(002).pdf

8 *See* "CAL FIRE Investigators Determine Causes of 12 Wildfires in Mendocino, Humboldt, Butte, Sonoma, Lake, and Napa Counties," News Release issued by Cal Fire, June 8,

date of this testimony, the cause of the most destructive wildfire in California history – the Tubbs Fire – has not been determined. PG&E currently faces dozens of lawsuits related to these wildfires, and although its ultimate liability for the 2017 wildfires is not yet known, investors have already reacted. Prior to the October 2017 wildfires, PG&E's stock was trading in the range of approximately \$65-70 per share. Immediately after the fires, the share price plummeted, and over the most recent six months of 2018 (through September), the stock price has been hovering in the range of approximately \$40-46 per share. Additionally, in December 2017, PG&E announced the suspension of the company's quarterly common stock and preferred stock dividends, citing uncertainty related to causes and potential liabilities associated with the October 2017 Northern California wildfires.[9]

In December 2017, catastrophic wildfires broke out in Southern California, burning more than 300,000 acres. Among these fires, the Thomas Fire became the largest wildfire in California history, until it was surpassed by the Mendocino Complex Fire in July 2018.[10] While the cause of the Thomas Fire has not been determined, numerous lawsuits have been filed against Southern California Edison ("SCE"), alleging involvement of the utility's equipment in the

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2018, available at http://calfire.ca.gov/communications/downloads/newsreleases/2018/2017_WildfireSiege_Cause.pdf

[9] *See* "PG&E Announces Suspension of Dividend, Citing Uncertainty Related to Causes and Potential Liabilities Associated with Northern California Wildfires," PG&E Press Release, December 20, 2017, available at http://investor.pgecorp.com/news-events/press-releases/press-release-details/2017/PGE-Announces-Suspension-of-Dividend-Citing-Uncertainty-Related-to-Causes-and-Potential-Liabilities-Associated-with-Northern-California-Wildfires/default.aspx

[10] *See* "Top 20 Largest California Wildfires," Cal Fire Fact Sheet.

ignition. SCE has also been sued for mudslides in Montecito, California that occurred in January 2018, with complaints alleging that the mudslides resulted from the fact that the Thomas Fire burned vegetation on the hillsides that might have prevented the mudslides from occurring. SCE has not been found liable for the Thomas Fire or the Montecito mudslides, but like PG&E, SCE's stock price has dropped significantly. Prior to these events, SCE's stock price was trading slightly above $80 per share, but it dropped below $65 per share by the end of December 2017, continued to decline for several months, and still has not returned to pre-Thomas Fire levels. Because the degree of liability associated with SCE's equipment is believed to be less severe, the equity impacts at SCE have been less acute than at PG&E.

The potential liability for the 2017 wildfires is substantial. According to the California Department of Insurance, statewide wildfire insurance claims for the October and December 2017 wildfires total nearly $12 billion.[11] A substantial portion of this liability may ultimately be borne by utility shareholders.

Q. Do you expect the frequency of or destruction caused by catastrophic wildfires to lessen anytime soon?

A. No. Five of the 20 most destructive wildfires in California history, as measured by Cal Fire, occurred in 2017, and a sixth joined the top 20 in 2018.[12] With climate change and prolonged periods of drought, the risk of wildfires is, if

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11 *See* "California Statewide Insurance Claims Nearly $12 Billion," Press Release issued by the California Department of Insurance, January 31, 2018, available at http://www.insurance.ca.gov/0400-news/0100-press-releases/2018/release013-18.cfm

12 *See* "Top 20 Most Destructive California Wildfires," Cal Fire Fact Sheet.

anything, increasing. Governor Jerry Brown has appropriately called the increased occurrence of catastrophic wildfires in California the "new normal."

Q. Is SDG&E attempting to reduce the risk associated with catastrophic wildfires?

A. Wildfire risk mitigation is a top priority at SDG&E. Since the 2007 wildfires, SDG&E has been engaged in a series of wildfire risk mitigation efforts, including the development of the largest utility-owned weather network, fire mapping activities, development of a fire potential index and Santa Ana Wildfire Threat Index, infrastructure hardening, aggressive vegetation management, revised operational protocols, contracting for firefighting resources, and using one of the world's largest water dropping heli-tanker.

While the goal behind these efforts is to avoid wildfire ignitions related to SDG&E facilities, SDG&E cannot entirely eliminate that risk. Furthermore, since California utilities are strictly liable for wildfire-related property damage and attorneys' fees under the legal doctrine of inverse condemnation, even where the utilities were not at fault, the utilities can incur billions in liabilities even for wildfire ignitions that are beyond their control.

Q. Are these catastrophic wildfire risks unique to California utilities?

A. In large part, they are unique to California utilities. Other states in the Western United States experience catastrophic wildfires, but California is one of only two states (along with Alabama) that subject private companies to inverse condemnation liability. Since, as noted above, SDG&E may be unable to recover liabilities arising from inverse condemnation lawsuits, the risk that utilities face in California is a product of the state's specific legal and regulatory environment.

Q. Can insurance be used to mitigate this risk?

A. SDG&E's ability to purchase insurance at a reasonable cost is influenced by worldwide insurance losses, particularly those relating to California. Several insurance companies that offer wildfire insurance have exited the California market due to the 2017 wildfires. As such, we experienced over 30% increase in our insurance costs in 2018 and we expect insurance costs to continue to increase over time given recent claims related to the 2017 wildfires. Indeed, in March 2018, Southern California Edison filed a request with the CPUC to recover approximately $108 million it incurred to obtain a 12-month, $300 million wildfire insurance policy for 2018. That is extremely expensive insurance coverage. So while insurance can certainly be a tool to mitigate risk, the scale of property damage seen in the 2007 wildfires and more recently provides cause for concern that insurance may not be enough, or that it will become too expensive.

Q. What happens if SDG&E experiences costs or liabilities from catastrophic wildfires that exceed its insurance coverage?

A. A loss that is not fully insured (or that cannot be recovered in customer rates) could adversely affect SDG&E's financial condition, cash flows and results of operations. SDG&E also faces situations that may not be covered by insurance (including costs in excess of applicable policy limits) or that may be disputed by insurers.

Q. Has the California Legislature sought to address the risk that utilities face with respect to catastrophic wildfires?

A. Yes, the Legislature recently passed Senate Bill 901 to address a range of issues related to catastrophic wildfires, which Governor Brown signed into law on September 21, 2018. Certain provisions directly impact utilities such as SDG&E. Although Governor Brown had proposed draft legislation in July that would have reformed inverse condemnation in certain respects, the Legislature did not pass that proposed inverse condemnation legislation.

Q. Has the recently-passed legislation had any immediate impact on SDG&E?

A. Yes. Credit rating agencies have reacted to the legislation by downgrading SDG&E's credit rating (as well as the credit ratings of PG&E and SCE). On September 5, 2018, Standard & Poors ("S&P") lowered SDG&E's credit rating from "A" to "A-." S&P's downgrade "reflects the unaddressed longer-term risks associated with inverse condemnation." S&P also maintained a negative credit outlook on SDG&E to "reflect the possibility of a lower rating if the severity of the California wildfires persist without a longer-term reform to inverse condemnation [and] if SDG&E is deemed the cause of a significant 2018 wildfire that leads to material disallowances." On September 6, 2018, Moody's downgraded SDG&E's credit rating from A2 to A1 citing "continued existence of inverse condemnation" as the principal rationale for the downgrade. On September 13, 2018, Fitch Ratings downgraded SDG&E credit ratings from A to A-, explaining that "the continuation of inverse condemnation, execution risk associated with the implementation of the proposed legislation, pressure on customer bills if cost recovery is approved in event of a major wildfire, and diminishing access to insurance will permanently overshadow SDG&E's credit profile. Senate Bill 901 and SDG&E's fire prevention and mitigation programs only provide partial mitigation of the rising regulatory risks for electric utilities operating in California."

If SDG&E were to experience a significant wildfire, there are two possible immediate consequences: (i) further credit rating downgrade and (ii) suspension of dividends. As indicated by credit rating agencies, further credit rating downgrade is highly likely in the event SDG&E is the cause of wildfires that leads to material losses in excess of insurance coverage. A credit rating downgrade from A to BAA (under Moody's rating system) could result in higher borrowing rates to the tune of 39 to 56 basis points, as shown in Table 2 below. While credit ratings directly impact borrowing rates, equity investors are attuned to the change in business risk profile that accompanies credit rating downgrades and would require a commensurate incremental ROE to compensate for the higher risk.

Table 2: Bond Yield Spread between A and BAA rated Public Utility Bonds

Spread Between A & BAA Rated Public Utility Bonds As of October 4, 2018			
	Moody's A Rated Public Utilities Bond Yield Avg	**Moody's BAA Rated Public Utilities Bond Yield Avg**	**Spread**
Spot	4.47%	4.89%	0.42%
2018 YTD Average	4.19%	4.58%	0.39%
3 Year Average	4.05%	4.61%	0.56%

Suspension of dividends is very punitive to equity investors as observed in PG&E's case. When PG&E announced suspension of dividends, PG&E's stock price plummeted 13%[13] the next day. Increased volatility in stock price is clear indication of higher risk and in the absence of dividend payments, equity investors seek higher ROE as a mean to restore total shareholder returns to levels prior to suspension of dividends.

Q. What market observations can you point to that demonstrate that investors view the risk of wildfires and inverse condemnation unfavorably, resulting in a lower valuation for SDG&E?

A. Numerous analyst reports from financial institutions indicate that SDG&E valuation has been assigned a 1-turn discount against regulated electric utility peer multiple due to potential future wildfire and inverse condemnation. The earnings multiple for regulated utility peer is 17.7, and a 1-turn discount thus results in an earnings multiple of 16.7 for SDG&E.[14] The fundamental assertion for determining the ROE premium under this approach is retaining market capitalization at non-discounted level which implies a ROE premium of 60 basis points.

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[13] PG&E announced suspension of dividends on December 20, 2017 after market close. The closing stock price for PG&E Corporation (PCG) on December 20, 2017 was $51.12. The closing price on December 21, 2017 was $44.50.

[14] Earnings multiple and discount as reported by Bank of America Merrill Lynch.

The derivation of ROE premium is shown in Table 3 below.

Table 3: ROE Premium Derived from Valuation Discount

	Regulated Utility Peer	SDG&E @ 1-turn Discount	Calculations
Earnings Multiple	17.7	16.7	(1)
Hypothetical Ratebase	$100	$100	(2)
Capital Structure – Common Equity	52%	52%	(3)
ROE	10.2%	10.2%	(4)
Annual Earnings	$5.3	$5.3	(5) = (2) x (3) x (4)
Market Capitalization	$93.8	$88.5	(6) = (1) x (5)
ROE Premium	**0%**	**0.60%**	(7)
Annual Earnings with ROE Premium	$5.3	$5.62	(8) = (2) x (3) x [(4) + (7)]
Market Capitalization with ROE Premium	**$93.8**	**$93.8**	(9) = (1) x (8)

B. Changes in the California Energy Industry

Q. Please describe the business risks associated with ongoing changes in the California energy industry.

A. The energy industry in California is in a period of unprecedented change as government policies, customer needs and technology innovation are transforming it to support a more environmentally sustainable future. Specific areas of change include technological infrastructure and cyber security; an increase in the usage of advanced technologies, such as rooftop solar and electric vehicles; an increase to renewable energy supply targets; and growing customer flexibility to choose their energy service provider. I discuss each of these in the following subsections.

When each factor is analyzed in isolation, it becomes clear that every factor poses a different type of risk to SDG&E. Because SDG&E must manage these major changes simultaneously, the risks are greatly amplified due to the interconnection and interdependency of the various factors, creating a systemic risk that is new, complex and difficult to track. Complex systemic risk is more likely to produce unforeseen or unpredictable outcomes. Investors will require a just and reasonable ROE to compensate for the higher risk profile caused by embedded systemic risk in SDG&E's business. Not only are these risks increasing for SDG&E, they are increasing at a rate above national utility averages. As discussed below, SDG&E is on the cutting edge of many new technologies with more exposure to risk than other utilities, such as the highest Rooftop Solar and the required Renewables Portfolio Standard ("RPS") levels.

1. Technology and Cyber Security

Q. Please describe the business risk associated with technology and cyber security.

A. In addition to general information and cyber risks that all Fortune 500 corporations face (*e.g.*, malware, malicious intent by insiders and inadvertent disclosure of sensitive information), the utility industry faces evolving cybersecurity risks associated with protecting sensitive and confidential information and its infrastructure. In July 2018, for example, there were widespread media reports of state-sponsored Russian attempts to hack the U.S. electric grid.[15]

2. Increase in Advanced Technologies

Q. Please describe the business risk associated with the increase in advanced technologies, such as rooftop solar and plug-in electric vehicles ("PEVs").

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15 https://www.nytimes.com/2018/07/27/us/politics/russian-hackers-electric-grid-elections-.html

A. The high adoption rate of rooftop solar[16] and plug-in electric vehicles ("PEVs")[17] in SDG&E's service territory means that SDG&E faces increased risk related to its transmission system. As the highly unpredictable and geographically diverse two-way energy flow from distributed generation and PEVs grows, the planning and operation of the transmission system becomes progressively more complex and riskier. Because SDG&E's customers are early adopters of these technologies, SDG&E does not have the luxury to wait and learn from other utilities on how to deal with the sea changes resulting from wide-scale implementation of these technologies. This market leader and early adopter position contributes to an investor's perception of a higher risk profile for SDG&E.

Areas with high concentration of PEVs pose significant risk to local distribution system reliability as transformers can become overloaded, leading to outages. In addition to the impact on reliability, the unexpected and potentially higher capital and operations & maintenance costs due to the potential for reduced life expectancy on existing infrastructure and the unpredictable future introduces variability to SDG&E's earnings.

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[16] https://environmentamerica.org/sites/environment/files/reports/EA_shiningcities2018_scrn%20%282%29.pdf

[17] https://www.spglobal.com/marketintelligence/en/news-insights/blog/electric-vehicle-infrastructure-u-s-utilities-are-getting-charged-up-but-are-regulators-plugged-in-to-the-concept

http://next10.org/sites/default/files/ca-zev-brief.pdf

3. Renewable Energy

Q. Please describe the business risk related to renewable energy procurement.

A. In 2002, California established its Renewables Portfolio Standard ("RPS"), pursuant to which utilities must increase their procurement of electricity from renewable sources. The RPS procurement percentages have increased over time to 50% of total procurement by 2030. In September, the Governor of California signed into law Senate Bill 100, which increases the standard to 60% by 2030, with a further increase to 100% by 2045. This is one of the most ambitious standards in the country.[18]

The business risk related to RPS derives from the fact that RPS compliance relies primarily upon power purchase agreements ("PPAs") between utilities and third-party developers, who may not be able to meet the terms of their agreements as a result of challenges such as (1) difficulty in obtaining project financing; (2) difficulty completing the permitting process; (3) transmission interconnection challenges; and (4) timely regulatory approval of projects. In the event that a project encounters one of these challenges, a utility may encounter difficult obtaining a viable replacement project in a timely manner. Further, non-compliance with the RPS may result in monetary penalties.

4. Customer Choice

Q. Please describe the business risk associated with growing flexibility for customers to choose their energy service provider, such as through Community Choice Aggregation ("CCA").

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[18] http://eta-publications.lbl.gov/sites/default/files/2017-annual-rps-summary-report.pdf

A. Community Choice Aggregation is a program that permits cities, counties, and other authorized entities – called Community Choice Aggregators – to purchase or generate electricity for residents and businesses located within the boundaries of their jurisdiction. Currently, SDG&E performs these procurement functions for its customers, excluding 0.9% of our customers participating in direct access and the City of Solana Beach discussed below.

Various cities within SDG&E's territory are exploring the adoption of a CCA program. In 2018, the City of Solana Beach became the first CCA program in SDG&E's service territory, and the City of San Diego is also exploring formation of a CCA Program. Estimates predict that most of the retail electric load served by California investor-owned utilities could be unbundled in the next decade.[19]

Electric procurement is a complex business and is subject to volatilities of the electric markets, as evident during the energy crisis that caused PG&E to file for bankruptcy protection in 2001. CCA programs are not immune to that financial risk. By default, SDG&E is the provider of last resort and would be required to accept returning customers should CCA programs not able to meet their obligations. If the customers they serve return to bundled utility service, this may add complexity to the market and create unplanned procurement obligations that could put a strain on SDG&E's balance sheet and cashflows.

[19] California Energy Commission, "2017 Integrated Energy Policy Report," p.30.

Q. Aren't some of the business risks you described in this Section specific to SDG&E's distribution business, and if so, should they be taken into account in this proceeding?

A. Certain of these risks (*e.g.*, Community Choice Aggregation) are related to SDG&E's state-regulated distribution business. But such risks are nevertheless relevant for setting SDG&E's ROE at this Commission because investors do not distinguish between transmission and distribution assets when investing in SDG&E (or its parent, Sempra Energy). In other words, the risks SDG&E faces cannot be allocated to transmission or distribution functions.

IV. FINANCIAL RISKS

Q. Please describe financial risk.

A. As described by Dr. Morin, financial risk stems from the method used by the company to finance its investments and is reflected in the utility's capital structure. As a utility's debt ratio increases, a higher return on equity may be needed to compensate for that increased risk. Thus, companies that issue more debt instruments have higher financial risk than companies that are financed mostly or entirely by equity.

When assessing the financial risk of a company, credit rating agencies and investors evaluate certain financial ratios, such as a company's capital structure, leverage, and cash flow adequacy.

Q. Can you provide some examples of financial risks that SDG&E faces?

A. Yes. Two significant examples result from long-term power purchase agreements ("PPA") and elevated levels of capital investment.

A. Long-Term PPAs

Q. Please describe the financial risk associated with long-term PPAs.

A. SDG&E has entered into substantial and increasing amounts of long-term PPAs, which may negatively impact credit ratings due to the credit rating agencies' treatment of PPAs as debt equivalence. SDG&E's power purchase commitment payments through 2022 are expected to total $3.65 billion, which is comprised of 10 new PPA's totaling $466 million. As renewable PPAs represent a growing component of the Company's overall energy portfolio, SDG&E expects the corresponding debt equivalent figure to continue to grow for the foreseeable future. Senate Bill 100 will serve to exacerbate this growth as California continues to be at the forefront of renewable energy adoption and increasing RPS requirements. As a result, SDG&E's financial ratios, as calculated by the rating agencies, may deteriorate and thus increase SDG&E's financial risk profile. Additionally, Accounting Standard Codification 810 (ASC 810) consolidation of certain PPAs into SDG&E's balance sheet could further deteriorate SDG&E's financial credit ratios.

B. Elevated Levels of Capital Investment

Q. Please describe the financial risk associated with elevated levels of capital investment.

A. Over the next five years, SDG&E plans to invest approximately $6.3 to $6.6 billion in capital projects. Capital investments include modernizing transmission and distribution infrastructure; and fire hardening measures to protect against extreme weather events and support public safety. SDG&E will be accessing the capital markets to finance these large capital investments and given the expected rising interest rates, SDG&E is exposed to interest rate risks. Higher interest rates translate to higher financing costs, which would put pressures on cashflows and earnings.

An elevated level of investment increases the risk of under-recovery or delayed recovery of the invested capital. Credit rating agencies and investors consistently analyze and focus on the effect that elevated capital investments may have on cash flows and corresponding pressure on credit metrics. Equity investors are equally aware of the pressure on cash flows associated with a utility's elevated capital investments and resultant effect on the cost of capital. To ensure that SDG&E has ready access to capital funding at a reasonable cost, SDG&E requires a just and reasonable ROE. SDG&E's proposed ROE will provide the cash flow necessary to sustain strong credit metrics appealing to both investors and rating agencies.

V. REGULATORY RISKS

Q. Please describe regulatory risk.

A. Regulatory risk refers to new risks that investors may face from future regulatory actions. The two main types of regulatory risks are (1) regulatory lag risk, and (2) cost recovery risk. Regulatory lag risk is related to the utility's ability to timely recover costs, which introduces uncertainty. Cost recovery risk is related to the utility's ability to consistently recover costs, and it reflects the risk of future regulatory actions, such as a disallowance of operating expenses and rate base additions. Rating agencies assess cost recovery risk and regulatory lag risk in setting utility bond ratings.

Q. Can you provide some examples of regulatory risks that SDG&E faces?

A. Yes. The most significant regulatory risk overlaps with one of the business risks I discussed above, namely the cost recovery risk that SDG&E may face for catastrophic wildfire liabilities. That is a very real risk that SDG&E encountered first-hand in 2017 and that has also directly impacted the other investor-owned utilities in California. Credit rating agencies and investors alike, have recognized California as having credit negative regulatory and legislative developments.

Q. Does this complete your testimony?

A. Yes.

VERIFICATION

Don Widjaja hereby declares under penalty of perjury of the laws of the United States that the foregoing document is true and correct to the best of his knowledge and belief. See 28 U.S.C. § 1746.

Executed this 30th day of October, 2018

Dony Widjaja