UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

SAN DIEGO GAS & ELECTRIC COMPANY) DOCKET NO. ER13-___-000

SAN DIEGO GAS & ELECTRIC COMPANY'S

TRANSMISSION OWNER TARIFF

TO4 FORMULA

VOLUME 3

FEBRUARY 15, 2013

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF ROBERT J. WIECZOREK ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY
EXHIBIT NO. SDG-8

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SUMMARY OF THE PREPARED DIRECT TESTIMONY OF
ROBERT J. WIECZOREK

Mr. Wieczorek's testimony provides support for the Electric Transmission average service lives (ASL), Iowa curves, and future net salvage (FNS) studies which are based on the recorded year 2011. These proposed depreciation parameters are used to establish depreciation accrual rates and/or future rate base for the Transmission Owner Formula at issue in this rate proceeding.

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ROBERT J. WIECZOREK
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY
(DEPRECIATION)

I. INTRODUCTION

Q1. Please state your name and address.

A1. My name is Robert J. Wieczorek. My business address is 8330 Century Park Court, San Diego, California 92123.

Q2. In what capacity are you employed?

A2. I am the Principal Depreciation Accountant for San Diego Gas & Electric Company (SDG&E).

Q3. Please describe your educational background and professional experience.

A3. A description of my background and qualifications are attached.

II. PURPOSE OF TESTIMONY

Q4. What is the purpose of your testimony in SDG&E's Transmission Owner (TO) Rate proceeding, designated as SDG&E's TO4 Formula?

A4. The purpose of my testimony is to support SDG&E's TO4 rate filing before the Federal Energy Regulatory Commission (FERC or Commission) by: (1) presenting the results of the average service life (ASL), Iowa curves, and future net salvage (FNS) analyses/studies that I conducted for SDG&E's transmission plant and (2) describing the methods I used in those studies to determine the life and net salvage characteristics of SDG&E's plant accounts to derive the depreciation expense for this TO4 Formula for SDG&E's Electric Transmission Plant.

III. EXECUTIVE SUMMARY

Q5. Please summarize the key components of your testimony.

A5. The key components of my testimony address the following:

- SDG&E has proposed for each FERC Uniform System of Accounts (USoA) subaccount the average service live (ASL), the appropriate Iowa curve, and the FNS all based upon historical 2011 data. SDG&E has also displayed an overall composite rate at a specific point in time using these aforementioned parameters. A comparison requested in the TO3 Settlement regarding cost of removal (COR) is included in this testimony.
- While there are displayed TO4 depreciation rates based on a specific point in time (May 2012 with Sunrise at July 2012), SDG&E is requesting that the proposed ASL, Iowa curve and FNS be accepted and therefore be the premise of rates going forward. SDG&E is proposing that rates be updated when necessary based on the final approval and authorization of these ASL, Iowa curves and FNS by subaccount. As changes in the infrastructure take place, SDG&E requests the option of rebuilding rates against those infrastructure changes applying the authorized ASL, Iowa curve, and FNS. This is similar to other Utility' requests in the Industry.
- Appendix VIII, specifically in paragraph titled "Transmission Plant Depreciation Expense", re-emphasizes the fact that the ASL, Iowa Curves, and FNS% are the proposed parameters requested for approval and authorization in this TO4 filing and not the rates that result from their application. SDG&E reserves the right to update rates over time using authorized parameters.
- The overall depreciation composite rate of 3.00% is the result of applying ASL, Iowa curves, and FNS study detail against FERC plant balances as of May 2012, except for the Sunrise Powerlink Project (Sunrise or SRPL) for which plant balances are displayed as of July 2012.
- The revenue requirement at May 2012 without Sunrise is $57.9M and the current May 2012 impact at the TO3 rates is approximately $47.5M for an increase of $10.4M. Once Sunrise is fully rolled in (based on a July 2012 balances), the revenue requirement will increase by an additional $42,831,086. See Appendix "D," page

BW-D4. Because of the operation of the Formula, the Sunrise effect will not occur until Cycle 2.

- The following chart displays the TO4 depreciation rates by Federal Energy Regulatory Commission (FERC or Commission) subaccount resulting from applying the proposed ASL, Iowa curve, and FNS parameters. Page BW-D1 in Appendix "D" reflects the TO3 Settlement depreciation rates which were approved by the FERC in 2007). Again, unlike the TO3 Settlement which authorized and approved specific depreciation rates, the current SDG&E request within this TO4 filing is requesting approval and authorization of the proposed ASL, Iowa curve, and FNS by FERC subaccounts.

TO4 - Transmission Plant Depreciation Rates @May 2012 (SRPL @July 2012

FERC Subaccount	Description	Proposed ASL	Proposed Iowa Curve	Plant Rate	Proposed FNS %	Net COR Rate	Total Rate
E352.10	"Other"	72	R2	1.36%	-60%	0.82%	2.18%
E352.20	"SWPL"	72	R2	1.01%	-60%	0.61%	1.62%
E352.60	"SRPL"	72	R2	1.39%	-60%	0.84%	2.23%
E353.10	"Other"	50	R1	2.20%	-60%	1.32%	3.52%
E353.20	"SWPL"	50	R1	2.51%	-60%	1.51%	4.02%
E353.40	"Palomar"	50	R1	2.03%	-60%	1.22%	3.25%
E353.60	"SRPL"	50	R1	2.01%	-60%	1.21%	3.22%
E354.10	"Other"	70	R5	1.57%	-100%	1.57%	3.13%
E354.20	"SWPL"	70	R5	1.33%	-100%	1.33%	2.65%
E354.60	"SRPL"	70	R5	1.47%	-100%	1.47%	2.93%
E355.10	"Other"	45	R1.5	2.33%	-100%	2.33%	4.65%
E355.20	"SWPL"	45	R1.5	2.54%	-100%	2.54%	5.08%
E355.60	"SRPL"	45	R1.5	2.26%	-100%	2.26%	4.53%
E356.10	"Other"	58	S0	1.60%	-100%	1.60%	3.20%
E356.20	"SWPL"	58	S0	0.88%	-100%	0.88%	1.77%
E356.60	"SRPL"	58	S0	1.75%	-100%	1.75%	3.51%
E357.00	"Other & SWPL"	60	R5	1.68%	-45%	0.75%	2.43%
E357.60	"SRPL"	60	R5	1.69%	-45%	0.76%	2.45%
E358.00	"Other & SWPL"	50	R3	1.89%	-10%	0.19%	2.08%
E358.60	"SRPL"	50	R3	2.03%	-10%	0.20%	2.23%
E359.10	"Other"	60	SQ	1.65%	0%	0.00%	1.65%

E359.20	"SWPL"	60	SQ	1.44%	0%	0.00%	1.44%
E359.60	"SRPL"	60	SQ	1.68%	0%	0.00%	1.68%
Composite				1.82%		1.18%	3.00%

IV. OVERVIEW OF METHODOLOGY USED TO DERIVE TO4 DEPRECIATION RATES

Q6. Please briefly explain the ASL Methodology.

A6. SDG&E uses the actuarial methodology for the transmission subaccounts that have the historical detail and retirement history necessary to support a thorough life study. For those subaccounts that do not provide the requisite historical detail, SDG&E exercises expert judgment in forecasting appropriate ASL, as described below:

- Only four (4) of the twenty-three (23) subaccounts (not including E350.26) provide the requisite data for an actuarial study which resulted in longer ASLs.
- The remaining nineteen (19) subaccounts are forecasted to reflect similar lives as suggested in the four (4) actuarial studies, comparable lives reflected by other CA utilities, or comparable lives embedded in the TO3 Settlement depreciation rates.
- The current TO4 composite plant rate displayed is 1.82%. (in contrast to the TO3 composite plant rate of 1.92%). This TO4 plant rate results from applying the proposed ASL and Iowa curve detail against the May 2012 historical FERC balances for "Other," *i.e.*, non-SRPL and Southwest Powerlink (SWPL) subaccounts but with the full impact of the newly energized Sunrise infrastructure balances at July 2012. Reflecting the Sunrise infrastructure at July 2012 lowers the TO4 composite plant rate not due to any ASL or Iowa curve differences but to the remaining lives expected for those assets.

Q7. Please briefly explain the FNS reflected in the TO4 Formula.

A7. The FNS study for the TO4 Formula captures the recent 15 year historical picture and when applied against the displayed plant rate of 1.82% supports a negative 65% factor equating to the 1.18%.

Q8. Please briefly explain the TO4 Composite Rates

A8. The displayed TO4 composite rate is a 1.82% plant rate with a 1.18% net cost of removal rate equating to the overall 3.00% composite rate. This contrasts with the authorized

TO3 composite plant rate of 1.92% with a .73% net cost of removal rate equating to the overall 2.65% settled authorized composite rate.

Q9. Section 6.3 of the TO3 Settlement requires SDG&E in its TO4 Filing "to produce an estimate of the prior amounts of Net Cost of Removal included in accumulated depreciation associated with the electric transmission facilities included in the filing, with full supporting documentation." How has SDG&E complied with that undertaking in this TO4 Filing?

A9. SDG&E has captured the removal accrual and percentage embedded within the monthly depreciation rates by transmission account for the entire TO3 life cycle (starts July 2007). SDG&E has also identified the actual removal cost expended and experienced during that same TO3 period (also starting, July 2007).

All FERC ACCOUNTS (Period July 1st 2007 thru December 2012)

YEAR (A)	PLANT RETIRED (B)	ACTUAL REMOVAL COST (C)	GROSS SALVAGE (D)	NET SALVAGE (GS less REM) (C - D) (E)	COR IN RATES (F)	DIFFERENCE (COR less NET SALVAGE) (F - E) (G)
2007	8,763,776*	2,692,863	-	2,692,863	4,444,028	1,751,165
2008	5,047,658	6,205,207	-	6,205,207	9,435,167	3,229,959
2009	6,010,000	12,433,857	871,432	11,562,425	10,493,752	-1,068,673
2010	11,559,893	9,632,555	-1,062	9,633,617	11,478,946	1,845,329
2011	5,608,148	15,047,902	2,802,409	12,245,493	12,681,908	436,415
2012	2,845,417	6,971,166	800,852	6,170,314	19,584,316	13,414,002
	39,834,892	52,983,550	4,473,631	48,509,919	68,118,116	19,608,197
	========	========	========	========	========	========
	* full year retirements		**Without Sunrise >**	**48,512,127**	**62,140,994**	**13,628,867**

1. The actual removal costs experienced and recorded during the TO3 period are a direct result of field removal and associated activity involved during transmission retirements.
2. The actual removal cost is not connected nor specifically related to the procedure that generates the COR accrual in the depreciation rates. Specifically, the COR depreciation accrual is simply a product of current infrastructure while the actual

removal cost is generated by experienced retirement activity. Costs and expenses are separate and uniquely independent, with no logical connections. Attempting to correlate these two numbers would yield misleading results.

Q10. Have you illustrated the effects of these various aspects of your methodology?

A10. Yes. I am including individual exhibits applying the proposed TO4 ASL, Iowa curves and FNS parameters both at 12/31/2011 and at 5/31/2012 which includes the Sunrise effect at 7/31/2012. The latter snapshot captures not only the effect of Sunrise but includes the extraction of the Citizens Lease[1] effect on future depreciation expense. See Appendix "D" for these exhibits illustrating the TO4 proposed parameters.

V. REMAINING LIFE METHODOLOGY

Q11. Please explain the methodology underlying your depreciation study for this TO4 Filing.

A11. The methods used to calculate the mortality characteristics (service lives, retirement dispersions, and net salvage rates) and to calculate the straight-line remaining life depreciation rates are based on the Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals (Standard Practice U-4). The California Public Utilities Commission (CPUC) issued this standard practice in 1961 as a guide for determining proper depreciation accruals, and has consistently upheld its use by the California utilities in computing service lives, retirement dispersions, and net salvage rates. California utilities have routinely used these same study methodologies in FERC proceedings.

Q12. Did you validate the study results?

A12. Yes. During the course of the depreciation study, results were reviewed and validated through a process which involved consulting the historical data for the assets as well as interacting with various operation departments to consider their observations and evaluations regarding SDG&E's capital assets and infrastructure. This process re-affirmed the study detail showing that existing infrastructure will continue the current life patterns (with some noted ASL extension) and FNS influence suggested by the studies and judgment, resulting in some lengthening of lives and increases in actual removal costs for certain FERC accounts. FNS has and is forecasted to increase for some specific

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[1] Citizens has entered into a 30 year lease for the $84.7M assets previously recorded for Sunrise. FERC has stipulated a 30 year amortization period.

FERC accounts. In addition, factors such as new technology, the continued heightened focus on safety, and the need for increased reliability of the SDG&E system all will have impacts to the ASL and FNS of assets, which are reflected in this TO4 Filing, and are anticipated to have impacts which will be reflected ongoing into future filings.

Q13. Other than history, are there other aspects to be considered when assessing and confirming ASL changes and future costs of removal?

A13. Yes. For example, new technology can definitely have the effect of either extending or reducing the lives of various assets. Focus on reliability can definitely have both an effect on ASL and/or cost of removal. Safety and environmental concerns are always paramount during utility operations. Future depreciation studies will continue to be conducted to weigh the influence and evaluate those effects on electric utility transmission assets.

Q14. How is the full year ending December 31, 2011 depreciation expense calculated?

A14. The depreciation expense for Recorded Year 2011 directly results from the application of depreciation parameters[2] authorized by the Commission in SDG&E's TO3 FERC Settlement.[3]

Q15. How will the initial TO4 depreciation rate affect depreciation on a going forward basis?

A15. Again, Life studies were established using historical data (through 2011) to analyze and adjust, where indicated, the assigned mortality characteristics of the FERC plant accounts. Beginning September 1, 2013, SDG&E proposes depreciation expense to be calculated using ASL, Iowa curves, and FNS that will be approved and authorized by the decision to this TO4 filing. The displayed the TO4 2013 annual depreciation expense results from applying the proposed ASL, Iowa curve, and FNS parameters against the infrastructure balances at May 2012 (exception for Sunrise FERC subaccounts using the July 2012 plant balances). SDG&E will update depreciation rates based on the authorized ASL, Iowa curve, and FNS due to infrastructure changes when necessary.

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2 Normally, “Depreciation parameters” (or “mortality characteristics”) refer to the average service life, retirement dispersion, and net salvage rate for a group of assets. In the TO3 settlement, the actual depreciation rates were authorized.

3 Doc No. ER07-284-000, Article VI – Composite Depreciation Rates

VI. DEPRECIABLE LIVES FOR THE TO4 FORMULA

Q16. What categories of FERC plant account depreciable lives did you review, study and/or forecast?

A16. Depreciable lives were reviewed, studied, and/or forecasted for two categories of plant accounts: (a) mortality accounts and (b) judgment/forecast accounts. Mortality accounts, generally referred to as mass accounts, maintain records for related types of property grouped by vintage year without regard to specific location. An example of a mortality account would be poles (FERC Account E355). Both categories are discussed in more detail below along with the Life Methods used.

A. Mortality Accounts

Q17. Does SDG&E apply the mass-asset convention of accounting?

A17. Many utilities including SDG&E apply the mass-asset convention of accounting known as the "group" method, as defined by the National Association of Regulatory Utility Commissioners (NARUC), to certain fixed assets such as utility poles and other components of their transmission systems. These FERC accounts can be too numerous to track on an individual basis given the number and relative value of each individual asset.

Q18. To what specific FERC accounts did SDG&E apply this mass-asset convention?

A18. Mortality characteristics were reviewed for the four (4) "Other" mortality accounts using historical data through 2011. By using the actuarial method, each of these four (4) subaccounts has been assigned a representative Iowa-type survivor curve[4] combined with an appropriate ASL.

Q19. What did this review determine?

A19. SDG&E's review indicated the need to propose modifications to the ASL for these accounts. The lengthening of ASL and increased FNS has been the general trend for SDG&E assets.

B. Judgment / Forecast Accounts

Q20. When is it appropriate to use Judgment/Forecast methodology?

[4] Iowa-type survivor curves plot the percent surviving (from an original asset placement group) versus the age of the group. The age is typically expressed as a percentage of average service life. The Iowa curves were developed from empirical industrial data, and are the most widely-used standardized survivor curves in the utility industry.

A20. For those FERC accounts that don't have the data or history that supports the Actuarial or Simulated Plant Record methodology, Judgment/Forecast methodology must be entertained to derive the proposed ASL and appropriate Iowa Curve.

Q21. Is it appropriate to identify a gain or loss during any asset retirement?

A21. Generally neither the mortality, forecast nor judgment methodology, using the composite convention of accounting, results in the recognition of a gain or loss upon the retirement of an asset. Rather, any difference between the net book value of the assets and the value realized at retirement (salvage proceeds less removal and disposal costs) are embedded in accumulated depreciation and considered in the determination of prospective depreciation rates.

C. Life Methods Used to Determine ASL

1. Retirement Rate Method of Actuarial Analysis (Actuarial Method)

Q22. What life methodology did you use to determine ASL?

A22. I used the retirement rate actuarial analysis as a primary determinant of average service lives for the four (4) mortality accounts that have the historical detail required.

Q23. What historical detail is needed for the actuarial analysis?

A23. Aged retirement data (i.e., the transaction year and the original vintage year) and exposures to retirement are required for this analysis. The retirements of a specified range of vintages (placement band) within a specified band of transactional calendar years (experience band) are identified, along with the age of each retirement. The retirements occurring at like-age intervals are grouped, with the same being done for the amounts exposed to retirements at the beginning of each age interval. These "exposures" also include adjustments for any major transfers between accounts.

Q24. While aged retirement data by vintage year is required, how does this data lend itself to in determining the survivor and/or Iowa curve?

A24. A survival rate is calculated for each age group by first dividing the retirements by the beginning exposures for a given age interval (to get a retirement rate) and then subtracting that rate from one (1). The survival rates (which represent the conditional probability of surviving the entire age interval) are multiplied successively, beginning with 100% at age zero, to arrive at percent surviving for the beginning of each age interval. These percentages are plotted and matched to standard survivor curves (Iowa-type survivor curves). When needed, the use of standard curves provides a good means of extrapolating incomplete survivor curves (known as "stub" or "truncated curves"). Truncated curves were not entertained in this study.

Q25. How is the ASL represented within the Iowa curve choice for any particular FERC Account?

A25. Average service lives are represented by the area under the survivor curve divided by the ordinate at age zero (100%). Vintage remaining lives are calculated by dividing the area under the survivor curve to the right of its age by the ordinate at that age. The average remaining life for each account was calculated by weighting the remaining life of each vintage year with its surviving plant balance as of December 31, 2011.

2. Forecast/Judgment Method of Analysis

Q26. What methodology did you use for those FERC accounts that do not capture the historical detail needed for an actuarial analysis?

A26. I applied forecast/judgment based on their association with the "Other" FERC accounts contained in the Actuarial analyses, as well as, the comparable FERC accounts reflected in recent filings by other California utilities.

Q27. What FERC accounts are being determined by the Forecast/Judgment method?

A27. Knowing that only four (4) "Other" FERC accounts have the recorded history to lend themselves to the actuarial methodology, the forecast/judgment methodology must be used to support and determine the ASL and Iowa Curve for the Southwest Powerlink (SWPL), Sunrise and the remaining "Other" FERC accounts. Again, this judgment uses the recorded history available, the recent TO3 Settlement results and the most recent SCE and PG&E TO filings, SDG&E Field and Engineering input, all combined with the actuarial data results detailed in the depreciation work papers.

VII. NET SALVAGE RATES FOR FERC TO4 FILING

Q28. Do the NARUC publications address salvage and have they issued guidance on this topic?

A28. As stated in the NARUC publication, *Public Utility Depreciation Practices*, "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. This percentage is referred to herein as a "FNS factor." The techniques employed depend upon the type of property being studied and the type of data available. These techniques can involve analysis of history, the anticipated future, or both. The procedures in general use have the ability to measure the salvage and cost of removal of the original installations, but rarely do so because of data limitations. If this situation is not recognized and compensated for, selected net salvage factors will be inconsistent with selected average service lives.

Q29. How have the many regulatory commissions handled salvage and cost of removal as a component of the depreciation rates?

A29. Historically, most 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 infrastructure that should be borne by the ratepayer during the asset's ASL. The latter is becoming more predominant over time.

Q30. How does the handling of salvage and cost of removal in this manner affect the utility customers?

A30. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, as well as the concept of intergenerational equity, which assigns removal costs for assets to the customers who have been served by those assets, no more, no less. The application of these principles requires that the estimated cost of removal of plant be recovered over its ASL."[5]

Q31. What actually happens when property is retired when there may be both positive salvage and cost to remove the infrastructure?

A31. NARUC also adds that when property is retired,[6] the effect of both salvage and removal costs are involved. The net salvage gives consideration to both of these items and represents the salvage less the removal costs. If the salvage exceeds the removal costs, the net salvage is considered positive. When the removal costs exceed the salvage, the net

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

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

salvage is negative. The effect of net salvage, whether positive or negative, must be considered in the calculation of depreciation.

Q32. How does this all come together in the current SDG&E historical analysis of net salvage?

A32. In this depreciation study, net salvage rates (equal to gross salvage less cost of removal as a percentage of retired plant cost) were proposed for SDG&E by analyzing historical data for the past 15 years (1997 through 2011).

Q33. Is this historical analysis a recognized approach to determine net salvage?

A33. Yes, it is based on that specified in the Standard Practice U-4.

Q34. Has there been a trend over time emerging from the recent SDG&E FNS studies?

A34. Yes. The prevailing trend of the SDG&E's FNS studies is towards more negative net salvage rates. Generally, a change in net salvage rates is directly related to the change in service lives (some transmission FERC accounts are lengthening at SDG&E) and has an offsetting impact on depreciation rates and expense. For example, when asset lives are lengthened, positive salvage values decline or become negative as the physical item continues to deteriorate and the cost to dispose of that item increases. Also, since the asset's vintage year reflects the original acquisition costs, the continually increasing cost of removal (*i.e.* labor costs) affects the ratio. The proposed FNS is expressed as a percentage of the original historical cost[7] of the associated retirement (a constant), and the current pattern being experienced at SDG&E are increasing negative net salvage rates. Thus, while a lengthening life (ASL extension) decreases annual depreciation expense, any increase in a negative net salvage rate will increase the depreciation expense.

Q35. Are the FNS study results for the TO4 Formula included in your testimony by FERC account?

A35. Yes. The specific TO4 FERC Filing proposals for each FERC asset account's net salvage are included in the account-by-account detail later in my testimony, as well as in Appendix "B". The individual proposed allocation by FERC account based on the FNS studies has increased for many of the FERC accounts from the current authorized levels.

[7] 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.

Q36. Is the historical cost of both positive salvage and removal activity available for review and analysis?

A36. Yes. SDG&E actual net salvage (positive salvage less actual removal) activity over the past years has been updated to include 2012 activity. Based on the FNS Study and this summary, the SDG&E overall FNS proposed in this TO4 filing is conservative:

Historical Removal.xls

VIII. DEPRECIATION RATE CALCULATION

Q37. What is one of the greatest challenges in depreciation rate calculation?

A37. 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. These rates can be so low that revenue fails to recoup the capital invested by the end of asset's end 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 inappropriately on current ratepayers, while future costs are minimal or non-existent.

Q38. What approach, objective, and/or considerations should be taken into account to address this challenge?

A38. The objective of computing depreciation then 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 different depreciation methods incorporated by SDG&E achieve this objective. As these methods are applied, two estimates are required, one for ASL and the other for FNS.

Q39. Is SDG&E using a prescribed method to calculate and determine depreciation rates?

A39. The SDG&E depreciation rates are calculated in accordance with Standard Practice U-4, using the straight-line method, broad group procedure, and remaining life technique. The straight-line method prorates the recovery of service value in equal annual amounts. The broad group 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 all had identical mortality characteristics, while using a single depreciation rate for the entire category. The broad group 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.

Q40. Can you explain how SDG&E calculates the remaining life annual accruals for each FERC account?

A40. Yes. 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.

Q41. Using recorded 12/31/2011 FERC plant balances, how were the annual depreciation rates calculated?

A41. The proposed ASL, Iowa curves, and FNS parameters are based on the December 31, 2011 historical data. The depreciation rates displayed on page BW-3 were calculated based on recorded information as of May and July, 2012. The net balance yet to be depreciated at those dates is divided by the remaining life to arrive at the yearly accrual. The actual depreciation rate is then determined for each FERC plant account by dividing the subsequent depreciation accrual by the full gross plant balance. These remaining life rates are self-correcting for prior over- and under-accruals as the depreciation parameters are updated in accordance with each subsequent FERC TO filings.

Q42. Knowing that the 12/31/2011 historical balances were used in the determination of both the ASL, Iowa curves, and FNS proposals, what historical detail was used in creation of the LIFE and COR subaccount rates?

A42. As stated above, rates are applied on a composite functional group basis to the 05/31/2012 and 07/31/2012 depreciable plant balances to obtain the displayed depreciation expense. The FERC composite depreciation rate resulting from the proposed study parameters (ASL, Iowa curves, and FNS) is 3.00 % for the 2013 TO4 Filing (generated on May/July 2012 historical), compared to a rate of 2.65% for the 2007 TO3 Settlement.

IX. ACCOUNT-BY-ACCOUNT DETAIL FOR PROPOSED ASL AND FNS PERCENTAGES

Q43. Has SDG&E identified a subaccount by subaccount summary of proposed ASL and FNS percentages?

A43. The following subaccount by subaccount detail summarizes the proposed lives and future net salvage for each transmission FERC subaccount. The method utilized in determining each FERC subaccount's updated and proposed life is also specified.

Q44. Will the method used in each FERC subaccount analysis be apparent?

A44. Within the summary for each account, it will be noted whether the Actuarial (mass account) and/ or the Forecast (best judgment) method was used in the analysis. For those specific FERC subaccounts where the Actuarial method was used as a primary determinant of average service lives, aged retirement data and exposures to retirement were required. As described earlier, the retirements of a specified range of vintages (placement band) within a specified band of transactional calendar years (experience band) were identified, along with the age of each retirement. The retirements occurring at like-age intervals are grouped, with the same being done for the amounts exposed to retirements at the beginning of each age. Work papers (Appendix "A" thru "D") detail the authorized and proposed service life and the calculation of the depreciation rate.

Q45. What additional detail is available for the Forecast/Judgment method by account?

A45. For those specific FERC subaccounts using the Forecast (best judgment) method, the forecast, life span, or end-life method of life analysis is normally applied for the remaining life calculation. These methods are outlined in Standard Practice U-4. Then, the composite remaining life for the account is obtained by direct weighting with the dollars for each unit. The average service life weighting is often only appropriate in situations where limited activity occurs within an account and there is a long time interval existing between probable retirement dates. For this TO4 filing, those FERC subaccounts not having the historical data necessary for an actuarial study, similar ASL, Iowa curves and FNS are being assigned (forecasted).

Q46. Was the prescribed 15 year FNS study used for the transmission FERC subaccounts?

A46. Yes. The FNS analysis was done in accordance with the Standard Practice U-4 methodology. While professional judgment was used in the review of the historical FNS study, being cognizant of the current authorized TO3 Settlement FNS percentages, as well as the other California utilities' authorized FNS rates were taken into consideration in arriving at the FNS rates being proposed in this TO4 Filing.

A. Subaccount E350.26 – Land Rights

Q47. Please describe the FERC E350.26 subaccount and the TO4 proposal being requested. Identify the type of assets assigned to this account, the method used to determine the proposed amortization specifically requested for this FERC account.

A47. This subaccount includes the acquisition costs for Land Rights. This includes land rights costs associated for "Other" transmission, SWPL and the recently completed Sunrise. This FERC subaccount for land and land rights shall include the cost of land owned in fee by the utility and rights. This also includes interests, and privileges held by the utility in land owned by others, such as leaseholds, easements, water and water power rights, diversion rights, submersion rights, rights-of-way, and other like interests in land.

The items of cost to be included in the accounts for land and land rights are as follows:

1. Bulkheads, buried, not requiring maintenance or replacement.
2. Cost, first, of acquisition including mortgages and other liens assumed (but not subsequent interest thereon).
3. Condemnation proceedings, including court and counsel costs.
4. Consents and abutting damages, payment for.
5. Conveyancer and notary fees.
6. Fees, commissions, and salaries to brokers, agents and others in connection with the acquisition of the land or land rights.
7. Leases, cost of voiding upon purchase to secure possession of land.

8. Removing, relocating, or reconstructing, property of others, such as buildings, highways, railroads, bridges, cemeteries, churches, telephone and power lines to acquire quiet possession.

9. Retaining walls unless identified with structures.

10. Special assessments levied by public authorities for public improvements on the basis of benefits for new roads, new bridges, new sewers, new curbing, new pavements, and other public improvements, but not taxes levied to provide for the maintenance of such improvements.

11. Surveys in connection with the acquisition, but not amounts paid for topographical surveys and maps where such costs are attributable to structures or plant equipment erected or to be erected or installed on such land.

12. Taxes assumed, accrued to date of transfer of title.

13. Title, examining, clearing, insuring and registering in connection with the acquisition and defending against claims relating to the period prior to the acquisition.

14. Appraisals prior to closing title.

15. Cost of dealing with distributees or legatees residing outside of the state or county, such as recording power of attorney, recording will or exemplification of will, recording satisfaction of state tax.

16. Filing satisfaction of mortgage.

17. Documentary stamps.

18. Photographs of property at acquisition.

19. Fees and expenses incurred in the acquisition of water rights and grants.

20. Cost of fill to extend bulkhead line over land under water, where riparian rights are held, which is not occasioned by the erection of a structure.

21. Sidewalks and curbs constructed by the utility on public property.

22. Labor and expenses in connection with securing rights of way, where performed by company employees and company agents.

The Forecast/Judgment method was used for this FERC subaccount and assets in this grouping and/or FERC subaccount will retire at a forecasted year in the future. Many of these assets have been acquired under contract specifying their end-life, so neither the Actuarial (A) nor the Simulated Plant Records (SPR) methodology would be appropriate.

SDG&E recommends that the forecast life for assets in this account remain at the current authorized forecasted amortized end-life currently set at 60/100 years or as dictated by specific contract end-life.

B. Account 352 – Structures and Improvements

Q48. Please describe the FERC E352 account and the TO4 proposals being requested for all the individual subaccounts (E352.10, E352.20 and E352.60). Identify the type of assets assigned to this account, the method used to determine the proposed ASL, Iowa curve, and the FNS percentages specifically requested for each unique FERC subaccount.

A48. This FERC account includes the cost in place of structures and improvements used in connection with all transmission operations.

1. Subaccount E352.10 – Structures and Improvements – "Other" Transmission

The available historical detail allows SDG&E the ability to complete an Actuarial Study on these assets. In the current actuarial study for FERC subaccount E352.10 "Other" Transmission, SDG&E observed a 72 year life for the R2 curve in the study detail reflecting historical activity through 2011. The ASL and Iowa curve study detail is available below and in Appendix "A":

C:352 Appdx A.pdf

Based on the updated FNS Study for this FERC subaccount E352.10, the costs associated with removal and disposal of the retired materials equates to FNS pattern of <60%>. SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <30%> to this proposed <60%>. The FNS supporting detail is included in Appendix "B".

2. Subaccount E352.20 – Structures and Improvements – South West Powerlink – SWPL – Transmission

This FERC subaccount includes the cost in place of structures and improvements used in connection with the SWPL transmission operations. Plant dollars reflected at 12/31/2011 in this E352.20 SWPL subaccount equate to about 10% of the total plant dollars that currently exist in the E352.10 "Other" subaccount. This minimal influence of overall plant dollars, while not exhibiting enough historical activity to incorporate the actuarial (A) or the SPR methodology, will be guided by the actuarial study done for the E352.10 "Other" subaccount (above). Thus a 72 ASL and R2 Iowa curve is being proposed for all the subaccounts under the entire full E352 FERC account.

Again, because of the minimal historical influence exhibited by E352.20, the FNS Study for FERC account E352.10 will essentially drive the costs associated with removal and disposal of the materials FNS of <60%>. Thus, SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <30%> to this proposed <60%>.

3. Subaccount E352.60 – Structures and Improvements – Sunrise Powerlink – SRPL – Transmission

This FERC account includes the cost in place of structures and improvements used in connection with Sunrise transmission operations. Sunrise has been in-service since mid-June 2012 and has no history that neither affects nor alters the proposal developed for the entire E352 FERC account. The Sunrise influence of overall plant dollars, while not exhibiting any activity to incorporate the actuarial (A) or the SPR methodology, will be guided by the actuarial study done for the E352.10 "Other" subaccount. Thus, a 72 ASL and R2 Iowa curve will be proposed for the entire full E352 FERC account.

Without any history to the contrary, it is anticipated that the FNS Study for FERC subaccount E352.10 (and applied to E352.20) should also be reflected as appropriate for this SRPL account E352.60. SDG&E is proposing that the FNS parameters match those requested for the E352 assets in the "Other" and "SWPL" accounts. This would establish an authorized negative net salvage rate increasing from the currently utilized <30%> upward to <60%>.

C. Account 353 – Station Equipment

Q49. Please describe the FERC E353 Account and the TO4 proposals being requested for all the individual subaccounts (E353.10, E353.20, E353.40, and E353.60). Identify the type of assets assigned to this account, the method used to determine the proposed ASL, Iowa curve, and the FNS percentage specifically requested for each unique FERC subaccount.

A49. This FERC account shall include the cost installed 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.

1. Subaccount E353.10 – Station Equipment – "Other"

The available historical detail allows SDG&E to perform an Actuarial Study on these assets. In the current Actuarial study for FERC account E353.10 "Other"

Transmission, SDG&E observed a 50 year ASL for the Iowa R1 curve in the study detail that has updated historical activity through 2011. SDG&E, therefore, is proposing an ASL of 50 years. ASL study detail is available below and in Appendix "A":

C:353 Appdx A.pdf

Based on the FNS Study for FERC subaccount E353.10, the costs associated with removal and disposal of the retired assets reflects an FNS of <60%>. Thus, SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <10%> to the proposed <60%>. The FNS supporting detail is included in Appendix "B".

2. Subaccount E353.20 – Station Equipment – SWPL

This FERC account includes the station equipment assets used in connection with SWPL transmission operations. Plant dollars reflected at 12/31/2011 in this E353.20 SWPL account equate to about 10% of the total plant dollars existing in the entire E353 FERC account. This minimal influence of overall plant dollars, while not exhibiting enough activity to incorporate the actuarial (A) or simulated plant records (SPR) methodology, will be guided by the actuarial study done for the E353.10 "Other" subaccount. Thus, SDG&E is proposing a 50 ASL and R1 Iowa curve for the entire full E352 FERC account.

Again because of the minimal influence exhibited by this SWPL FERC E353.20, the FNS Study for FERC account E352.10 will essentially drive the costs associated with removal and disposal of the infrastructure. Thus, SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <10%> to this proposed <60%>.

3. Subaccount E353.40 – Station Equipment – Palomar

This FERC account includes the station equipment assets used in connection with Palomar transmission operations. Plant dollars reflected at 12/31/2011 in this E353.40 subaccount are minimal at $1.6 million. This minimal influence of overall plant dollars, while not exhibiting enough activity to incorporate the actuarial (A) or SPR methodology, will be guided by the actuarial study done for the E353.10 "Other" subaccount. Thus, SDG&E is proposing a 50 ASL and R1 Iowa curve for the entire full E353 FERC account.

Again because of the minimal influence exhibited by this Palomar FERC E353.40, the FNS Study for FERC account E353.10 will essentially drive the costs associated with removal and disposal of the infrastructure. Thus, SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <10%> to this proposed <60%>.

4. Subaccount E353.60 – Station Equipment – SRPL

This FERC subaccount includes the station equipment assets used in connection with the SRPL transmission operations. Sunrise has been in-service since mid-June 2012 and has no history that either affects or alters the proposal developed for the entire E353 FERC account. The Sunrise influence of overall plant dollars, while not exhibiting any activity to incorporate the actuarial (A) or the simulated plant records (SPR) methodology, will be guided by the actuarial study done for the E353.10 "Other" subaccount. Thus SDG&E proposes a 50 ASL and R1 Iowa curve for the entire full E353 FERC account.

Without any history to the contrary, it is anticipated that the FNS Study for FERC subaccount E353.10 (also E353.20 & E353.40) should also be reflected as appropriate for this SRPL subaccount E353.60. SDG&E is proposing that the FNS parameters match those requested for the E353 assets in the "Other", "Palomar" and "SWPL" subaccounts. This would establish an authorized negative net salvage rate increasing from the currently utilized <10%> upward to <60%>.

D. FERC Account 354 – Towers and Fixtures

Q50. Please describe the FERC E354 account and the TO4 proposals being requested for all the individual subaccounts (E354.10, E354.20 and E354.60). Identify the type of assets assigned to this account, the method used to determine the proposed ASL, Iowa curve, and the FNS percentage specifically requested for each unique FERC subaccount.

A50. This FERC account shall include the cost installed of towers and appurtenant fixtures used for supporting overhead transmission conductors.

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.

1. Account E354.10 – Towers and Fixtures – Other

There is not enough historical detail within the SDG&E records to complete an Actuarial Study on these assets. Since the July 2007 settlement, a 70 year ASL with a SQ Iowa Curve has been in place. SDG&E is proposing to continue with the ASL of 70 years but updating to the Iowa curve to R5.

The FNS Study for FERC subaccount E354.10 has been updated and the costs associated with removal and disposal of the materials equates to a FNS of <100%>. Thus, SDG&E is requesting an authorized change from the current negative net salvage rate of <75%> to the proposed <100%>. The FNS supporting detail is included in Appendix “B”.

2. Subaccount E354.20 – Towers and Fixtures – SWPL

Again, there is not enough historical detail to complete an Actuarial Study on these SWPL assets. Again, since the July 2007 settlement, a 70 year ASL with a SQ Iowa Curve has been in place. SDG&E is proposing to continue with the current ASL of 70 years but with the R5 Iowa curve.

Based on the FNS Study for FERC subaccount E354.10, the costs associated with removal and disposal of the materials equates to a FNS of <100%>. Thus, SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <75%> to the proposed <100%>.

3. Subaccount E354.60 – Towers and Fixtures – SRPL – Sunrise

Again, there is no history available for these recently installed Sunrise assets to complete an Actuarial or SPR Study. SDG&E is proposing the ASL of 70 years with the R5 Iowa curve.

Based on the FNS Study for FERC subaccount E354.10, the costs associated with removal and disposal of the materials equates to a FNS of <100%>. Thus, SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <75%> to the proposed <100%>.

E. FERC Account 355 – Poles and Fixtures

Q51. Please describe the FERC E355 account and the TO4 proposals being requested for all the individual subaccounts (E355.10, E355.20, & E355.60). Identify the type of assets assigned to this account, the method used to determine the proposed ASL, Iowa curve, and the FNS percentage specifically requested for each unique FERC subaccount.

A51. This FERC account shall include the cost installed of transmission line poles, 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.

1. Subaccount E355.10 – Poles and Fixtures – Other

The available historical detail allows SDG&E the ability to complete an Actuarial Study on these assets. Since the SDG&E TO3 Settlement, a 42 year ASL with a R1.5 Iowa Curve has been in place for this full FERC account. Reviewing the Actuarial detail and study available at that time, which used historical data through the year 2005, a shorter average service life of 40 years was actually reflected in those SDG&E study results along with the R1.5 Iowa Curve.

In the current SDG&E Actuarial study for FERC subaccount E355.10 "Other" Transmission, a 38 year life for the R1 Iowa curve is observed in that study detail that has updated historical activity through 2011. There have been numerous "wood to steel" change-outs since the TO3 filing for fire safety focus at SDG&E and those are instrumental, within the current actuarial study findings, in lowering the ASL. SDG&E will continue to complete planned future "wood to steel" projects. These will also (in the short term) influence the studies thus continuing to lower the ASL due to the retirement activity.

Review of this data has taken place with field and engineering personnel that have confirmed the activity within the actuarial study but they also suggest that the actual impact of new steel poles will result in the extension of the FERC subaccount's ASL over the next decade. Knowing that this switch-out of pole material will help to extend the life of those assets, it should reflect an extension of the ASL in future life studies closer to that approved for other California utilities. The logic there is that the new pole life should exceed what is currently being observed. SDG&E is therefore recommending that the study results be reviewed with that in mind and approved with an updated forecasted ASL of 45 years. The actual SDG&E proposal will be to extend the current ASL from 42 years to 45 years with the Iowa curve staying at R1.5. ASL study detail is available below and included within Appendix A:

C:355 Appdx A.pdf

Based on the FNS Study for FERC account E355.10, the costs associated with removal and disposal of the materials is increasing the FNS to <100%>. SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <80%> to the proposed <100%>. The FNS supporting detail is included in Appendix "B".

2. Subaccount E355.20 – Poles and Fixtures SWPL – Other

The historical activity available is not sufficient to complete an Actuarial nor SPR life and Iowa curve study for this FERC subaccount. The proposal recommended for the previous FERC E355.10 subaccount will be utilized for this FERC subaccount. Therefore, SDG&E proposes the same 45 year ASL and R1.5 Iowa curve. This extends the ASL from the current 42 years.

Similarly based on the FNS Study for the previously mentioned FERC subaccount E355.10, the costs associated with removal and disposal of the materials is increasing the FNS to <100%>. SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <80%> to the proposed <100%>.

3. Subaccount E355.60 – Poles and Fixtures – SRPL – Sunrise

There is no historical activity available for the SRPL FERC subaccount E355.60 due to its recent introduction to our infrastructure (June 2012). So no Actuarial or SPR life study, including an Iowa curve distinction, can be forecasted independently for this FERC subaccount. The proposal determined for the FERC E355.10 subaccount (matching that for E355.20) will be utilized for this FERC subaccount. Therefore, SDG&E proposes the same 45 year ASL and R1.5 Iowa curve.

Similarly based on the FNS Study for the previously mentioned FERC subaccount E355.10 & E355.20, the costs associated with removal and disposal of the materials is increasing the FNS to <100%>. SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <80%> to the proposed <100%>.

F. Account 356 – Overhead Conductors and Devices

Q52. Please describe the FERC E356 account and the TO4 proposals being requested for all the individual subaccounts (E356.10, E356.20, & E356.60). Identify the type of assets assigned to this account, the method used to determine the proposed ASL, Iowa curve, and the FNS percentage specifically requested for each unique FERC subaccount.

A52. This FERC account shall include the cost installed of overhead conductors and devices used for transmission purposes.

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.

1. Subaccount E356.10 – Overhead Conductors and Devices – Other

The available historical detail allows SDG&E the ability to complete an Actuarial Study on these E356.10 assets. Since the SDG&E TO3 Settlement, a 54 year ASL with a SQ Iowa Curve has been used for this subaccount. Reviewing the Actuarial detail and study available at that time, which used historical data through the year 2005, a longer average service life at 57 years was actually reflected in the results mapped against the authorized SQ Iowa Curve.

In the current Actuarial study for FERC subaccount E356.10 "Other" Transmission, a 58 year life for the S0 Iowa curve is observed in the study detail that has updated historical activity through 2011. SDG&E is proposing a change in the ASL to 58 years using the S0 Iowa curve. ASL study detail is available below and in Appendix "A":

C:356 Appdx A.pdf

Based on the FNS Study for FERC subaccount E356.10, the costs associated with removal and disposal of the materials is increasing the FNS to <100%>. Therefore, SDG&E is requesting an authorized change from the currently utilized negative net salvage rate from <95%> to <100%>. The FNS supporting detail is included in Appendix "B".

2. Subaccount E356.20 – Overhead Conductors and Devices – SWPL

There is not enough historical detail to complete an independent Actuarial Study on these E356.20 assets. Again, since the TO3 Settlement, a 54 year ASL with a SQ Iowa Curve has been used for this subaccount. Reviewing the Actuarial detail (for 356.10) and study available at that time, which used historical data through the year 2005, a longer average service life at 57 years was actually reflected in the results mapped against the authorized SQ Iowa Curve.

In the current Actuarial study for FERC subaccount E356.10 "Other" Transmission, a 58 year life for the S0 Iowa curve is observed in the study detail that has updated historical activity through 2011. SDG&E is proposing a change in the ASL to 58 years and utilize the S0 Iowa Curve.

Based on the FNS Study for FERC subaccount E356.10, the costs associated with removal and disposal of the materials is increasing the FNS to <100%>. Therefore, SDG&E is requesting an authorized change from the currently utilized negative net salvage rate from <95%> to <100%>.

3. Subaccount E356.60 – Overhead Conductors and Devices – SRPL – Sunrise

There is no historical activity available for the SRPL FERC subaccount E356.60 due to its recent introduction to our infrastructure (June 2012). So no Actuarial or SPR life study, including an Iowa curve distinction, can be forecasted independently for this FERC subaccount. The proposal determined for the FERC E356.10 account (matching that for E356.20) will be utilized for this FERC subaccount. Therefore, SDG&E proposes the same 58 year ASL and S0 Iowa curve. This extends the ASL from the currently reflected 54 years that was used for similar assets since the TO3 filing.

Similarly based on the FNS Study for the previously mentioned FERC subaccount E356.10 & E356.20, the costs associated with removal and disposal of the materials is increasing the FNS to <100%>. SDG&E is requesting an authorized change from the currently utilized negative net salvage rate of <95%> to the proposed <100%>.

G. Account 357- Underground Conduit and Cables

Q53. Please describe the FERC E357 account and the TO4 proposals being requested for all the individual subaccounts (E357.00 & E357.60). Identify the type of assets assigned to this account, the method used to determine the proposed ASL, Iowa curve, and the FNS percentage specifically requested for each unique FERC subaccount.

A53. This FERC account shall include the cost installed of underground conduit and tunnels 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.

1. Subaccount E357.00 – Transmission Underground Conduit – Other and SWPL

There is not enough historical detail within the SDG&E records to complete an Actuarial Study on these E357 assets. Assets in this account are comprised of both "Other" and "SWPL" infrastructure. Since the TO3 Settlement, a 60 year ASL with a SQ Iowa Curve has been identified for this account. Without concrete detail to deviate from the current authorized ASL, SDG&E is proposing that the 60 year ASL continue but updated with the R5 Iowa curve. Continuation of this ASL is comparable to other CA utilities.

Based on the FNS Study for FERC subaccount E357.00, the costs associated with removal and disposal of the materials FNS is reflecting <80%>. Activity during the past five (5) years has been minimal which does not suggest nor warrant the FNS to be at that high level. Therefore, SDG&E is not requesting nor proposing to change from the currently utilized negative net salvage rate of <45%>. The FNS supporting detail is included in Appendix "B".

2. Subaccount E357.60 – Transmission Underground Conduit – SRPL

There is no historical activity available for the SRPL FERC subaccount E357.60 due to its recent introduction to our infrastructure (June 2012). So no Actuarial or SPR life study, including an Iowa curve distinction, can be forecasted independently for this FERC subaccount. The proposal determined for the FERC E357 subaccount will be utilized for this FERC subaccount. Therefore, SDG&E proposes the same 60 year ASL and R5 Iowa curve.

Similarly based on the FNS Study for the previously mentioned FERC subaccount E357, the costs associated with removal and disposal of the materials is reflecting the FNS at <80%>. Activity during the past five (5) years has been minimal which does not suggest nor warrant the FNS to be at that high level. Therefore, SDG&E is not requesting nor proposing to change from the currently utilized negative net salvage rate of <45%>.

H. FERC Account 358 – Underground Conductors and Devices

Q54. Please describe the FERC E358 account and the TO4 proposals being requested for all the individual subaccounts (E358.00 and E358.60). Identify the type of assets assigned to this account, the method used to determine the proposed ASL, Iowa curve, and the FNS percentage specifically requested for each unique FERC subaccount.

A54. This FERC account shall include the cost installed of underground conductors 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.

1. Subaccount E358.00 – Transmission Underground Conductors and Devices – Other and SWPL

There is not enough historical detail within the SDG&E records to complete an Actuarial Study on these E358.00 assets. Assets in this account are comprised of both "Other" and "SWPL" infrastructure. Since the SDG&E TO3 Settlement, a 50 year ASL with a SQ Iowa Curve has been used for this FERC account. Without concrete detail to deviate from the current authorized ASL, SDG&E is proposing that the existing ASL at 50 years continue but utilizing the R3 Iowa curve.

Based on the FNS Study for FERC account E358.00, the costs associated with removal and disposal of the materials FNS remains steady at <10%> Therefore, SDG&E is not requesting a change from the currently utilized negative net salvage rate of <10%>. The FNS supporting detail is included in Appendix "B".

2. Subaccount E358.60 – Transmission Underground Conductors & Devices – SRPL

There is no historical activity available for the SRPL FERC subaccount E358.60 due to its recent introduction to our infrastructure (June 2012). So no Actuarial or SPR life study, including an Iowa curve distinction, can be forecasted independently for this FERC subaccount. The proposal determined for the FERC E358.00 subaccount will be utilized for this FERC subaccount. Therefore, SDG&E proposes the same 50 year ASL and R3 Iowa curve.

Similarly based on the FNS Study for the previously mentioned FERC subaccount E358.00, the costs associated with removal and disposal of the materials for this Sunrise subaccount 358.60 should remain steady at <10%> Therefore, SDG&E is not requesting a change from the currently utilized negative net salvage rate of <10%>.

I. FERC Account 359 – Roads & Trails

Q55. Please describe the FERC E359 account and the TO4 proposals being requested for all the individual subaccounts (E359.10, E359.20 and E359.60). Identify the type of assets assigned to this account, the method used to determine the proposed ASL, Iowa curve, and the FNS percentage specifically requested for each unique FERC subaccount.

A55. This FERC account shall include the 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 items included herein.
5. Trails, including grading, surfacing, culverts, etc.

1. Subaccount E359.10 – Roads and Trails – Other

There is not enough historical detail within the SDG&E records to complete an Actuarial Study on these E359.10 assets. Since the TO3 Settlement, a 60 year ASL with a SQ Iowa Curve has been in place.

Without concrete detail to deviate from the ASL, SDG&E is proposing that the existing ASL continue with the same SQ Iowa curve. This ASL is comparable to other California utilities.

Based on the FNS Study for FERC account E359.10, the costs associated with removal and disposal of the materials FNS remains steady at <0%> Therefore, SDG&E is not requesting a change from the currently utilized negative net salvage rate of <0%>. The FNS supporting detail is included in Appendix "B".

2. Subaccount E359.20 – Roads and Trails – SWPL

There is not enough historical detail within the SDG&E records to complete an Actuarial Study on these E359.20 assets. Since the SDG&E TO3 Settlement, a 60 year ASL with a SQ Iowa Curve has been used. Without concrete detail to deviate from the current ASL, SDG&E is proposing that the existing ASL continue with the same SQ Iowa curve. Both are comparable to other California utilities.

Based on the FNS Study for FERC subaccount E359.10, the costs associated with removal and disposal of the materials FNS remains steady at <0%> SDG&E recommends that this subaccount (E359.20) reflect that same FNS. Therefore, SDG&E is not requesting a change from the currently utilized negative net salvage rate of <0%>.

3. Subaccount E359.60 – Roads and Trails – SRPL – Sunrise

There is no historical activity available for the SRPL FERC subaccount E359.60 due to its recent introduction to our infrastructure (June 2012). So no Actuarial or SPR life study, including an Iowa curve distinction, can be forecasted independently for this FERC subaccount. The proposal requested for the FERC E359.10 and E359.20 subaccounts will be utilized for this FERC E359.60 subaccount. Therefore, SDG&E proposes the same 60 year ASL and SQ Iowa curve.

Similarly based on the FNS Study for the previously mentioned FERC subaccount E359.10 and E359.20, the costs associated with removal and disposal of the materials for this Sunrise account 359.60 should remain steady at <0%> Therefore, SDG&E is not requesting a change from the currently utilized negative net salvage rate of <0%>.

X. HISTORICAL REMOVAL STUDIES

Q56. Has SDG&E been able to segregate and capture the embedded authorized COR within the depreciation rates since the inception of the TO3 Formula in July 2007?

A56. SDG&E has captured the removal accrual and percentage embedded within the monthly depreciation rates by transmission account for the TO3 life cycle through 2012 (starts July 2007).

Q57. Has SDG&E been able to segregate and capture the actual COR that occurs when assets are retired and physically removed from the transmission infrastructure?

A57. SDG&E has also identified the actual removal cost expended and experienced during that same TO3 period (also starting, July 2007).

Q58. How is the depreciation accrual generated?

A58. The depreciation accrual (both the COR and LIFE portions) are based and tied directly to settlement parameters. Incorporating the remaining life of the assets into the equation establishes the actual yearly effect on the SDG&E ratepayers. Both are products generated by assets that exist on the books and that have yet to be removed and/or retired (in other words, still "used and useful") from the infrastructure during the month that the accrual is generated.

Q59. What drives the actual cost of removal activity?

A59. The actual removal costs experienced and recorded during the TO3 period is a direct result of field removal and associated activity involved during transmission retirements.

Q60. Isn't it logical to make a simple comparison between the COR depreciation accrual and the actual removal cost for reasonableness?

A60. The actual removal cost is not connected nor specifically related (<u>nor should it be</u>) to the procedure that generates the COR and LIFE accruals mentioned previously. The COR depreciation accrual is simply a product of current infrastructure while the actual removal cost is generated by experienced retirement activity. These are separate and uniquely independent, with no logical connections. To make a determination, comparison, or conclusion that would simply state or imply that these two numbers should equate, would be erroneous. As with many transmission infrastructures, the full impact of actual removal occurs at the end-life of an asset. It is imperative to capture the appropriate portion of this future removal activity from the ratepayer that is using the asset. To arbitrarily reduce depreciation rates in favor of the current ratepayer at the expense of burdening the future ratepayer is contrary and inconsistent with intergenerational equity.

Q61. Do retirement patterns have an effect on ASL studies and FNS percentages?

A61. LIFE history updates and changes (extending and shortening lives) are affected and influenced by recorded transmission retirements during the historical period. Removal activity occurs as retirements are initiated by field personnel. Also, the longer an asset remains in the SDG&E infrastructure (i.e., "used and useful"), past patterns typically suggest that positive salvage will evaporate while actual removal cost expended against the original assets' installation costs will increase. As FNS studies are updated each TO filing, those positive salvage and actual removal patterns are captured within the 15 year historical view.

Q62. Knowing that the two numbers are uniquely independent, is SDG&E able to present a simple comparison of COR accruals verses actual removal costs?

A62. Because it was requested during the TO3 Settlement filing, SDG&E is showing the COR numbers generated by current plant infrastructure (July 2007 through 2012) embedded within the accrual rates along with the actual removal cost that was specifically generated by the yearly retirement activity. See the summary chart details displayed within this testimony on page "BW-5" and in Appendix "C":

WITNESS QUALIFICATIONS

My name is Robert J. Wieczorek. My business address is 8330 Century Park Court, San Diego, California 92123. I am employed by San Diego Gas & Electric Company (SDG&E) as a Principal Accountant in the Accounting Operations Department. I have held this position since 2007. My principal duties include the preparation of depreciation estimates and special depreciation-related studies, and the monitoring of depreciation and valuation practices used by SDG&E and Southern California Gas Company (SoCalGas). Those duties include depreciation, amortization, salvage studies, and life studies for proceedings before the California Public Utilities Commission and the Federal Energy Regulatory Commission.

I received an AA degree in Mathematics from Glendale College in 1970, a Bachelor of Science degree in Accounting from Northridge (CSUN) in 1979, and an MBA from National University in 2002. Currently, I hold a Certified Compensation Professional Certificate (through 2013). I have taken depreciation course work developed by the Society of Depreciation Professionals. Prior to assuming my current position, my work experience at SoCalGas, Sempra Corp, and SDG&E has involved physical gas field work, field accounting, depreciation accounting, various staff positions at Gas Transmission and Distribution, Organization and Compensation, Regulatory, and Human Resources.

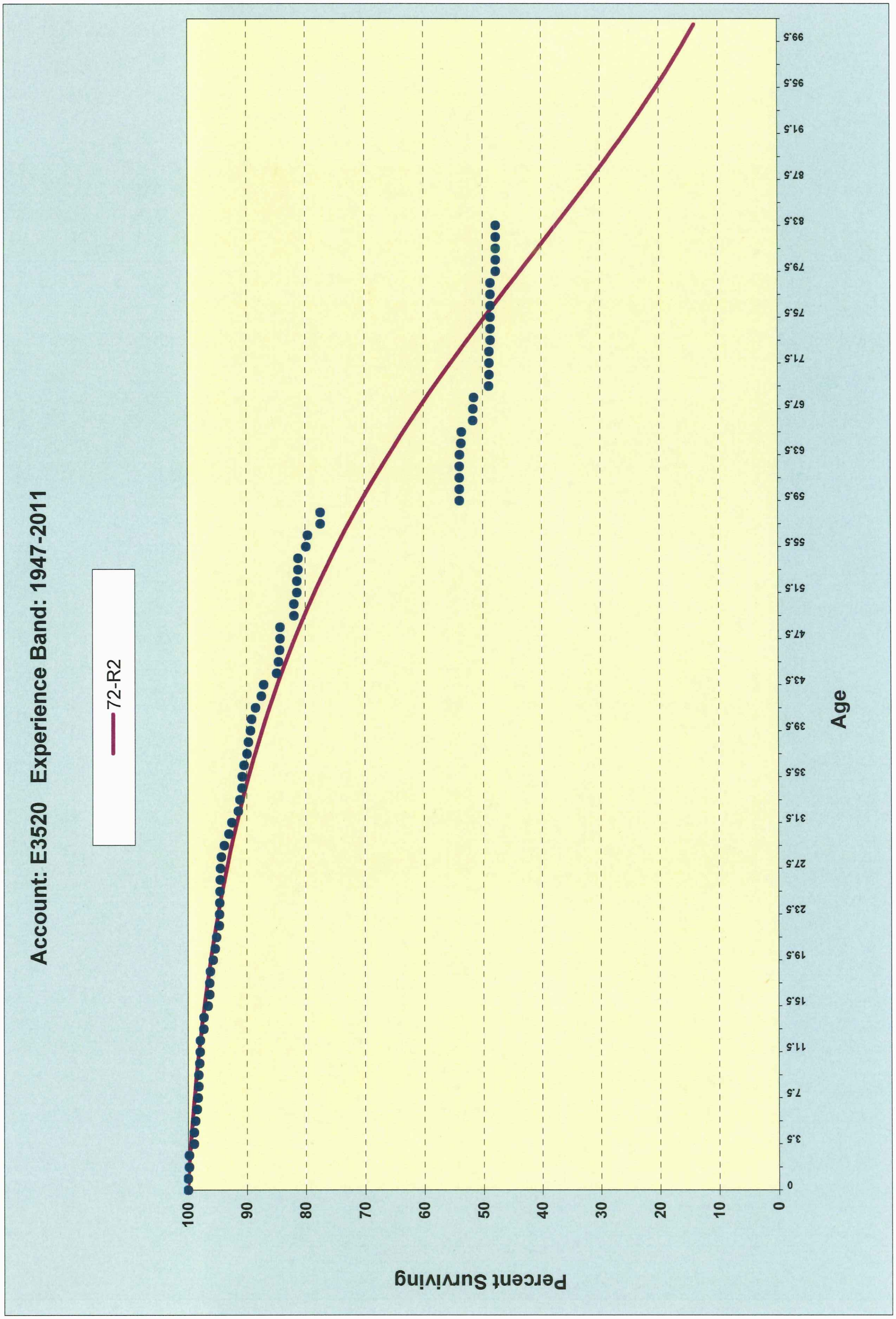
I have previously testified before the CPUC in December 2011 for both SDG&E and SoCalGas as the depreciation witness in their recent 2012 General Rate Case proceeding. I have not previously testified before the FERC.

This concludes my prepared direct testimony.

APPENDIX "A"

LIFE (ASL & IOWA CURVE) STUDY DETAIL

T04 ANALYSIS



Account: E3520 Experience Band: 1947-2011
72-R2
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
Age
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
31.5
35.5
39.5
43.5
47.5
51.5
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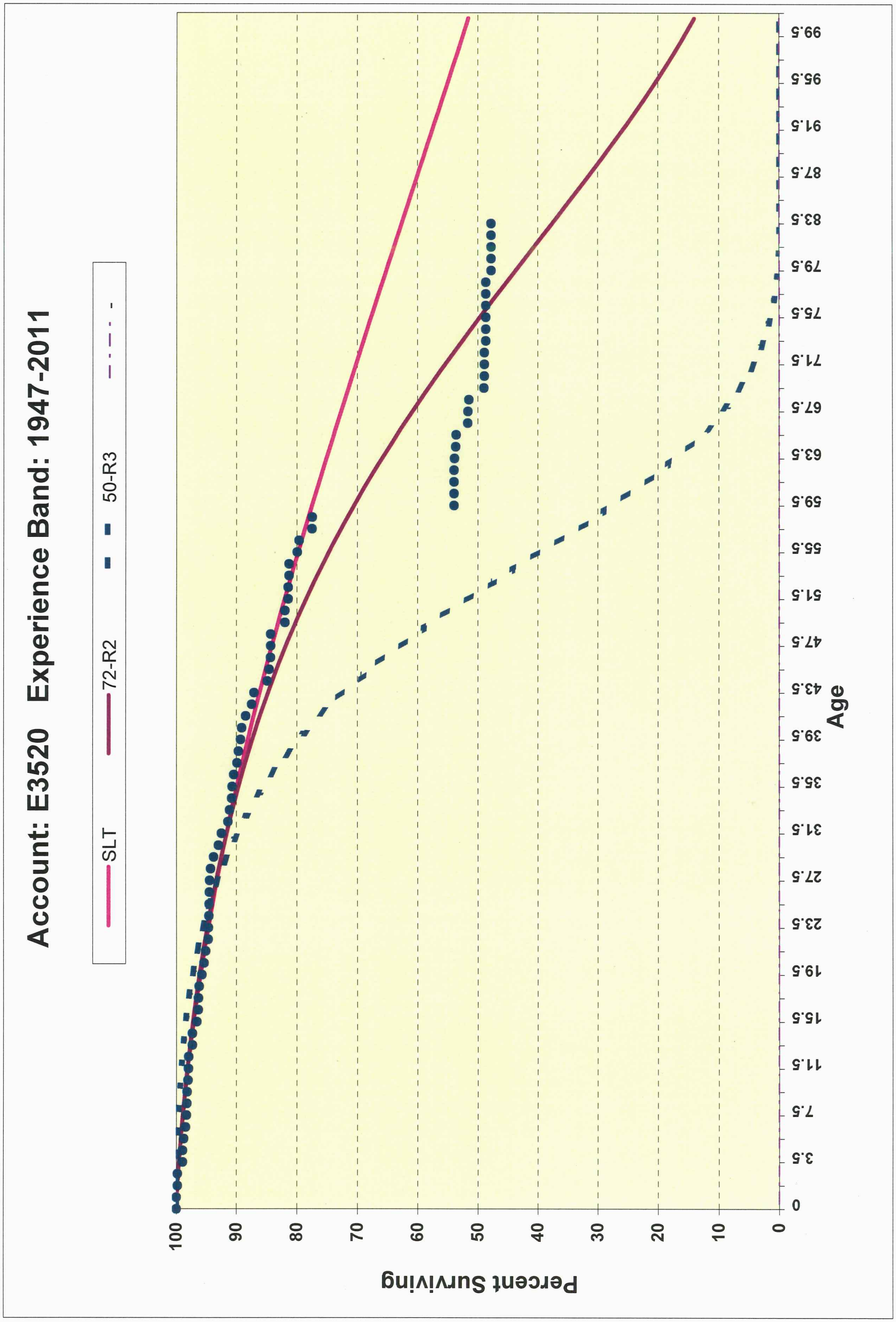
91.5
95.5
99.5


Account: E3520 Experience Band: 1947-2011
SLT
72-R2
50-R3
Percent Surviving
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90
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70
60
50
40
30
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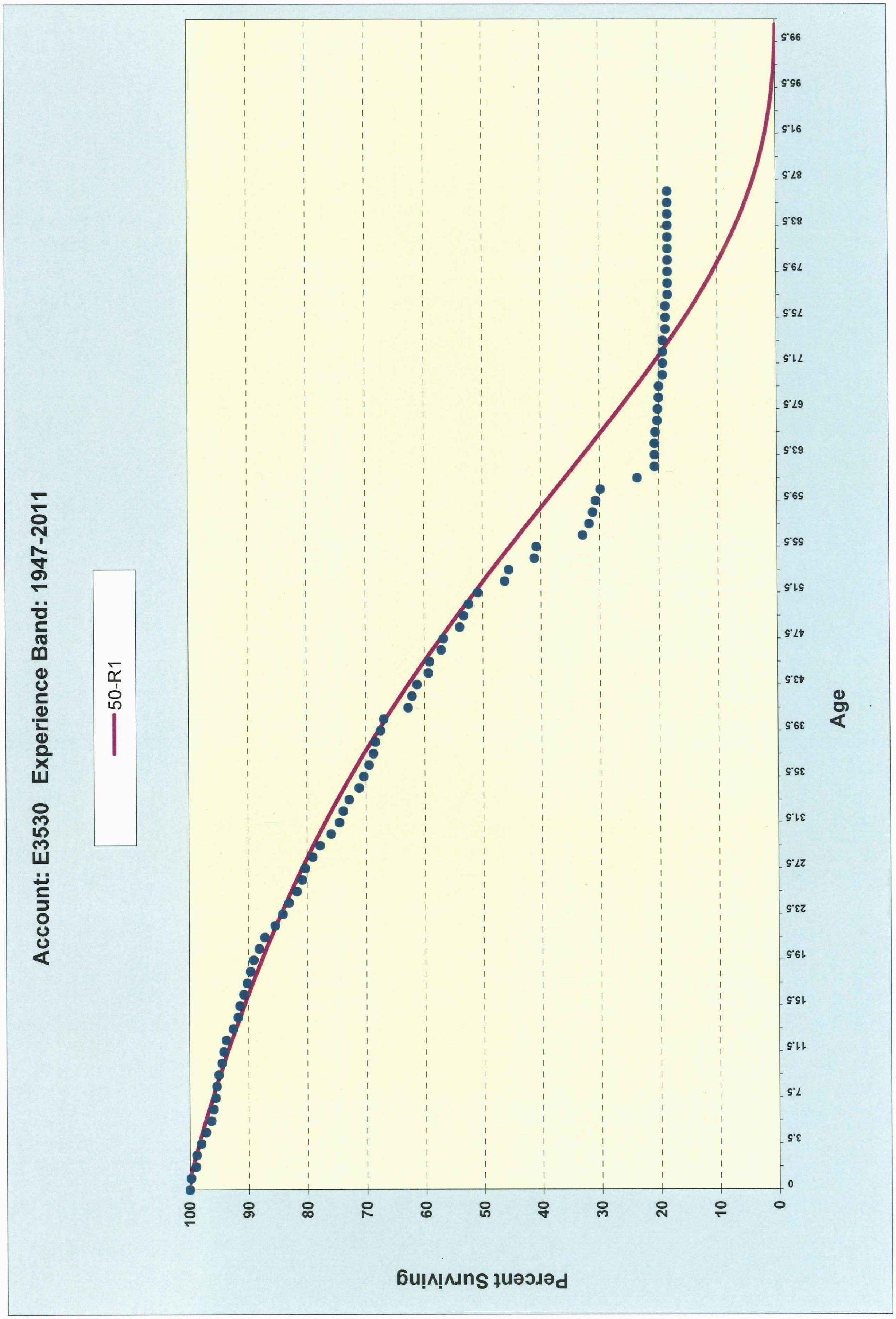
10
0
Age
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
31.5
35.5
39.5
43.5
47.5
51.5
55.5
59.5
63.5
67.5
71.5
75.5
79.5
83.5
87.5
91.5
95.5
99.5

Account: E3520 Experience Band: 1947-2011
Observed Life Table (OLT)

Iowa Curve Type	Curve No.	Average Service Life	Sum of Squared Deviations
L2	17	79.37	1727.197
L1.5	16	81.64	1909.623
S1	5	75.50	1951.362
S1.5	6	74.27	2075.148
R2	24	72.45	2238.353
S0.5	4	77.18	2323.310
R1.5	23	73.76	2652.941
L1	15	85.21	2718.787
S2	7	73.45	2736.583
R2.5	25	71.93	2754.187
S0	3	79.71	3173.087
L3	18	75.43	3335.423
R1	22	76.04	3726.534
L0.5	14	89.53	3738.348
R3	26	71.72	4054.490
S-0.5	2	83.85	4859.090
L0	13	95.65	5111.614
R0.5	21	81.47	5427.139
S3	8	72.60	5527.950
SC	1	91.13	7078.884
L4	19	72.81	8361.045
R4	27	72.21	8872.161
S4	9	72.50	12043.238
L5	20	72.52	16150.057
R5	28	73.35	18585.145
S5	10	73.10	22023.562
S6	11	74.37	34561.077

Account: E3520 Experience Band: 1947-2011
Smoothed Life Table (SLT)

Iowa Curve Type	Curve No.	Average Service Life	Sum of Squared Deviations
L0.5	14	110.14	220.513
L1	15	110.48	405.076
L0	13	109.56	2040.784
S-0.5	2	107.37	2096.099
L1.5	16	111.08	2508.607
R0.5	21	106.94	2797.022
S0	3	108.73	3122.173
SC	1	105.56	4237.337
R1	22	107.80	5604.258
S0.5	4	109.45	5871.426
L2	17	111.42	6844.890
R1.5	23	108.53	9852.106
S1	5	109.97	10666.733
S1.5	6	110.17	16584.869
R2	24	108.98	16955.921
L3	18	111.05	21851.834
S2	7	110.21	24350.615
R2.5	25	109.23	25019.031
R3	26	109.25	35648.749
S3	8	109.80	41331.310
L4	19	109.73	46666.281
R4	27	108.81	56225.836
S4	9	108.71	64902.316
L5	20	108.43	70881.717
R5	28	107.69	81704.004
S5	10	107.37	87774.903
S6	11	105.96	107934.471
SQ	12	102.01	146231.577


Account: E3530 Experience Band: 1947-2011
50-R1
Percent Surviving
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60
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40
30
20
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Age
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
31.5
35.5
39.5
43.5
47.5
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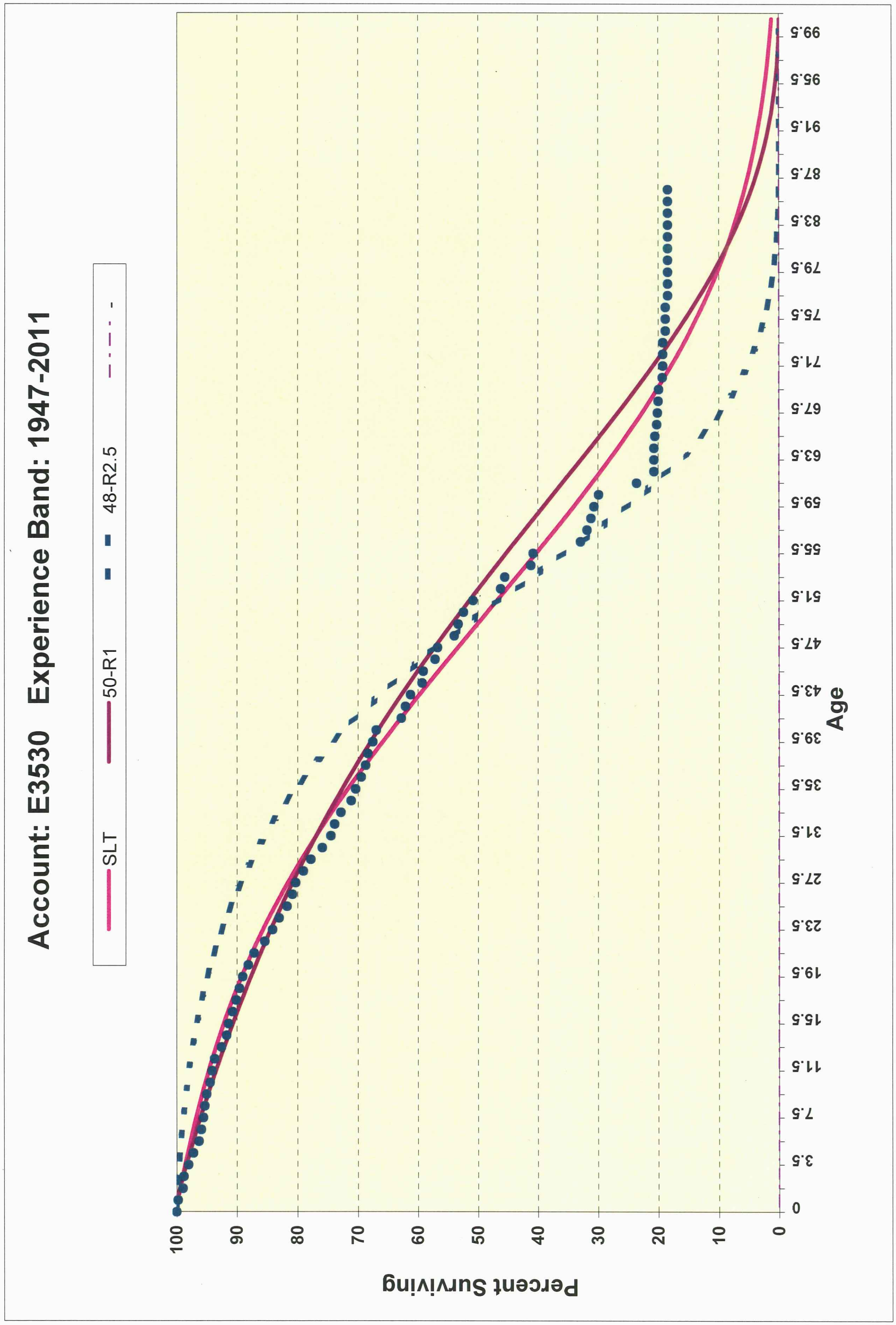
91.5
95.5
99.5


Account: E3530 Experience Band: 1947-2011
SLT
50-R1
48-R2.5
Percent Surviving
Age
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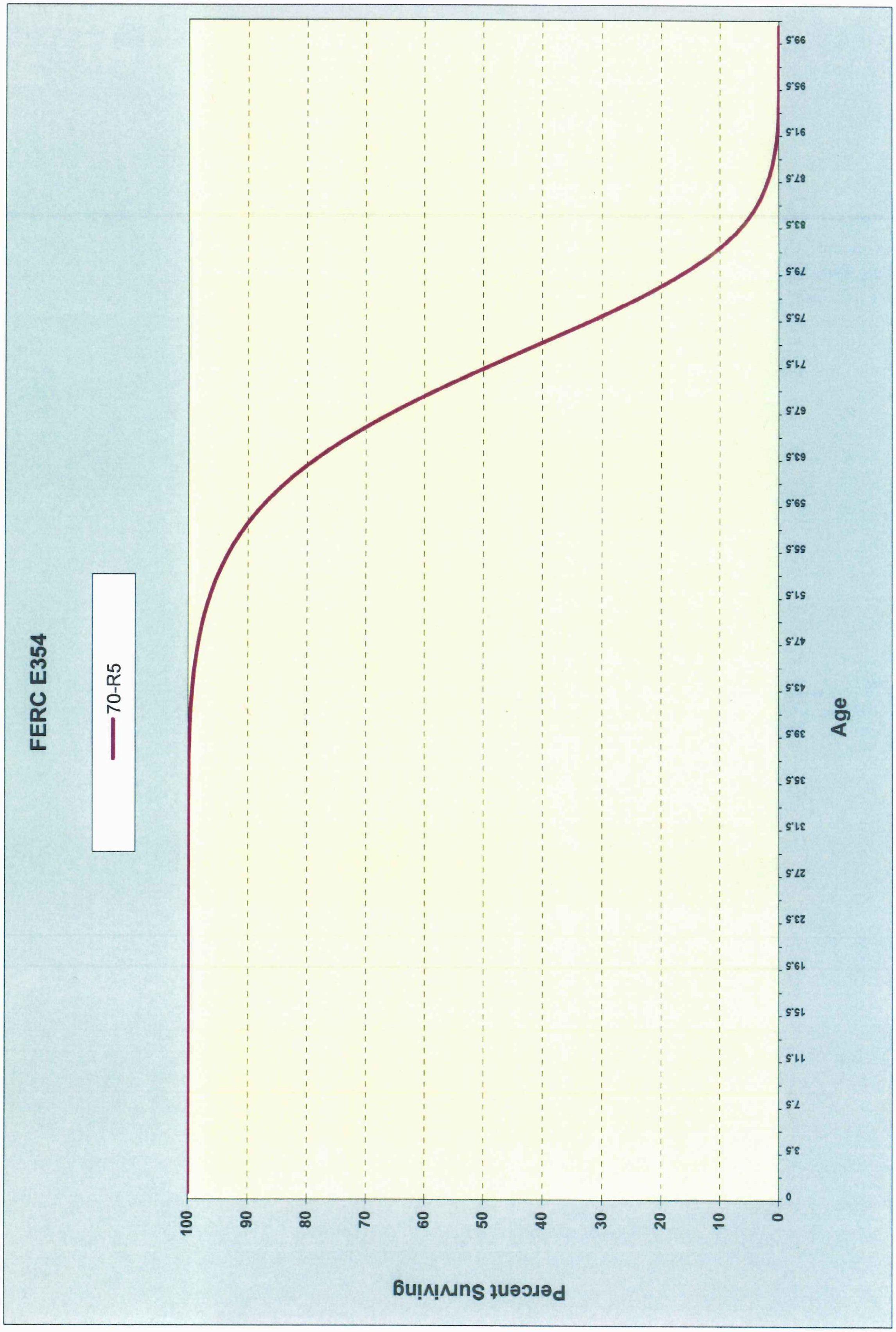
20
10
0
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
31.5
35.5
39.5
43.5
47.5
51.5
55.5
59.5
63.5
67.5
71.5
75.5
79.5
83.5
87.5
91.5
95.5
99.5

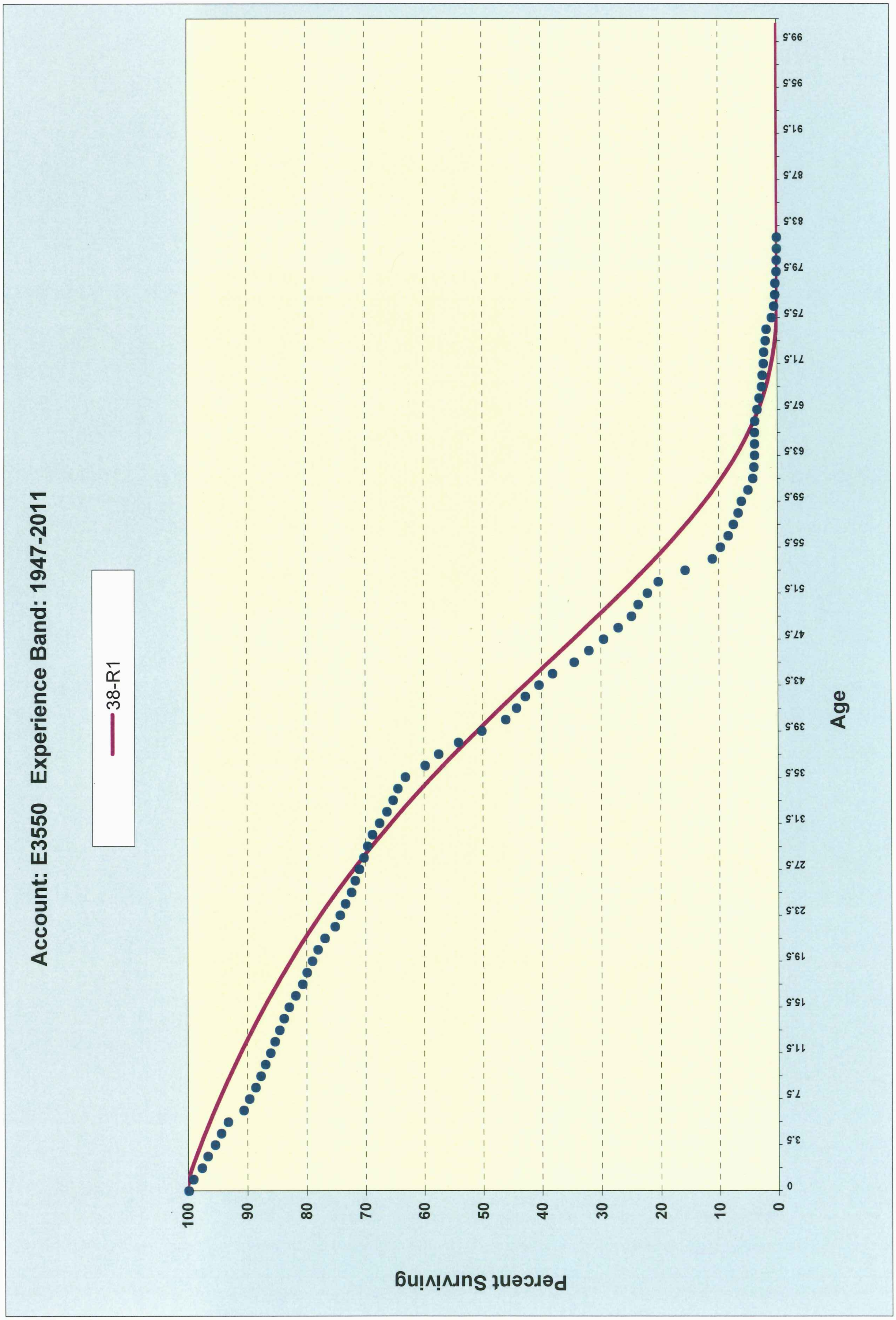
Account: E3530 Experience Band: 1947-2011
Observed Life Table (OLT)

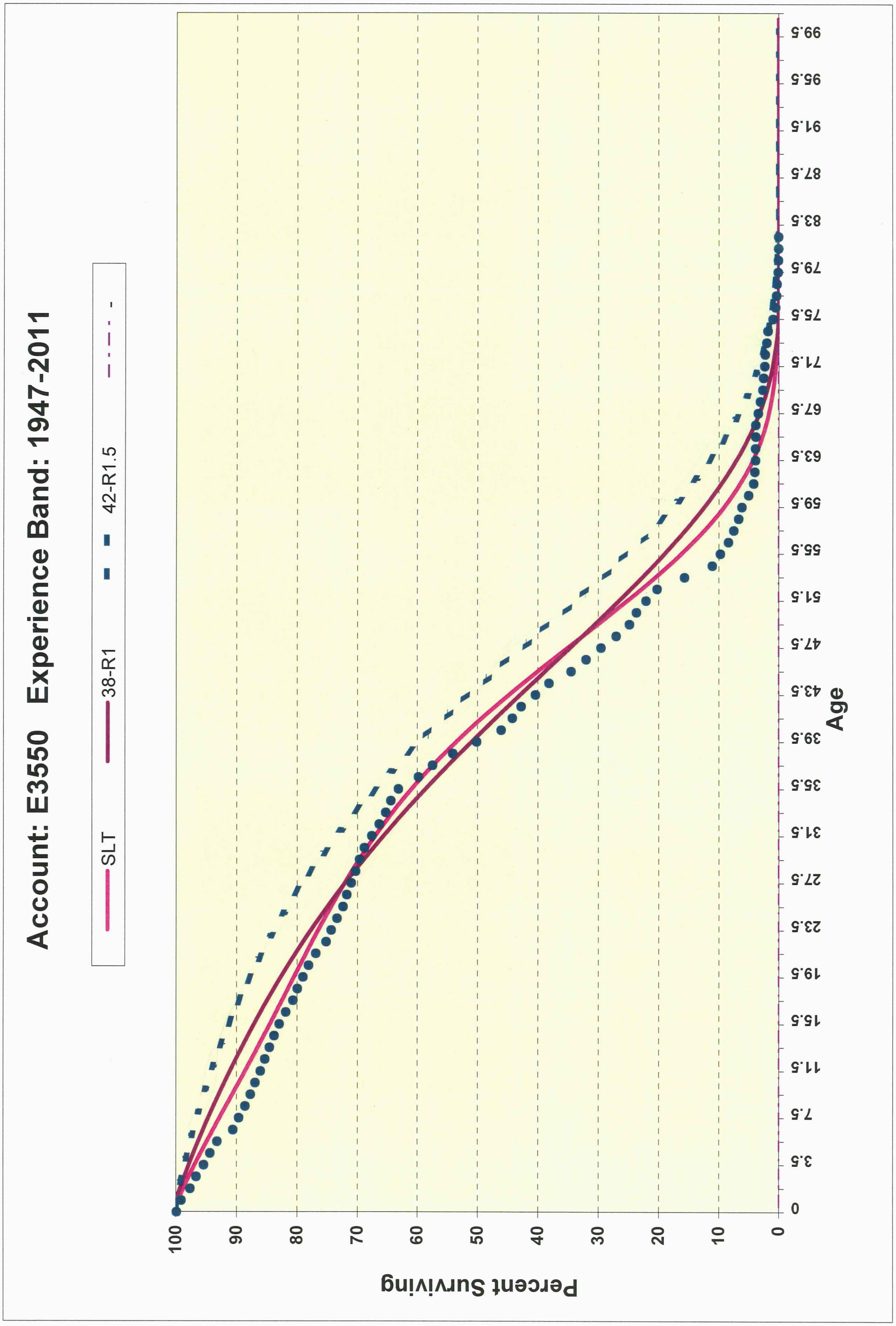
Iowa Curve Type	Curve No.	Average Service Life	Sum of Squared Deviations
L1.5	16	52.53	1468.991
L1	15	52.31	1620.566
S0	3	50.73	1810.200
S0.5	4	51.12	1963.071
R1	22	50.14	2271.985
L2	17	52.68	2278.210
L0.5	14	52.60	2291.084
R0.5	21	49.68	2540.875
S-0.5	2	50.04	2547.754
R1.5	23	50.50	2826.119
S1	5	51.47	3022.940
L0	13	52.97	3690.565
S1.5	6	51.64	4548.229
SC	1	49.23	4638.712
R2	24	50.79	4683.096
L3	18	52.71	6218.452
R2.5	25	50.94	6876.651
S2	7	51.75	6928.100
R3	26	50.99	10264.506
S3	8	51.76	12403.408
L4	19	52.39	14185.711
R4	27	51.34	17014.623
S4	9	51.82	20494.430
L5	20	52.19	22822.364
R5	28	51.89	26347.729
S5	10	52.04	28935.596
S6	11	52.44	37081.576

Account: E3530 Experience Band: 1947-2011
Smoothed Life Table (SLT)

Iowa Curve Type	Curve No.	Average Service Life	Sum of Squared Deviations
S0.5	4	49.27	193.360
S0	3	48.67	239.175
R1	22	48.34	297.830
L1.5	16	50.11	616.009
R1.5	23	48.97	725.091
S1	5	49.76	1005.468
L2	17	50.52	1084.536
R0.5	21	47.60	1108.085
L1	15	49.57	1110.093
S-0.5	2	47.73	1330.686
R2	24	49.49	2363.606
S1.5	6	50.13	2446.180
L0.5	14	49.30	2466.241
SC	1	46.62	3667.709
L3	18	50.86	4599.519
L0	13	48.92	4690.733
S2	7	50.41	4698.962
R2.5	25	49.87	4747.144
R3	26	50.21	8263.641
S3	8	50.63	10392.070
L4	19	50.82	12594.086
R4	27	50.51	15877.045
S4	9	50.64	19326.179
L5	20	50.68	21883.315
R5	28	50.51	26198.510
S5	10	50.31	28773.416
S6	11	50.22	37579.102
SQ	12	48.27	54019.599


FERC E354
70-R5
Percent Surviving
Age


Account: E3550 Experience Band: 1947-2011
38-R1
Percent Surviving
Age


Account: E3550 Experience Band: 1947-2011
SLT
38-R1
42-R1.5
-
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
Age
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
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43.5
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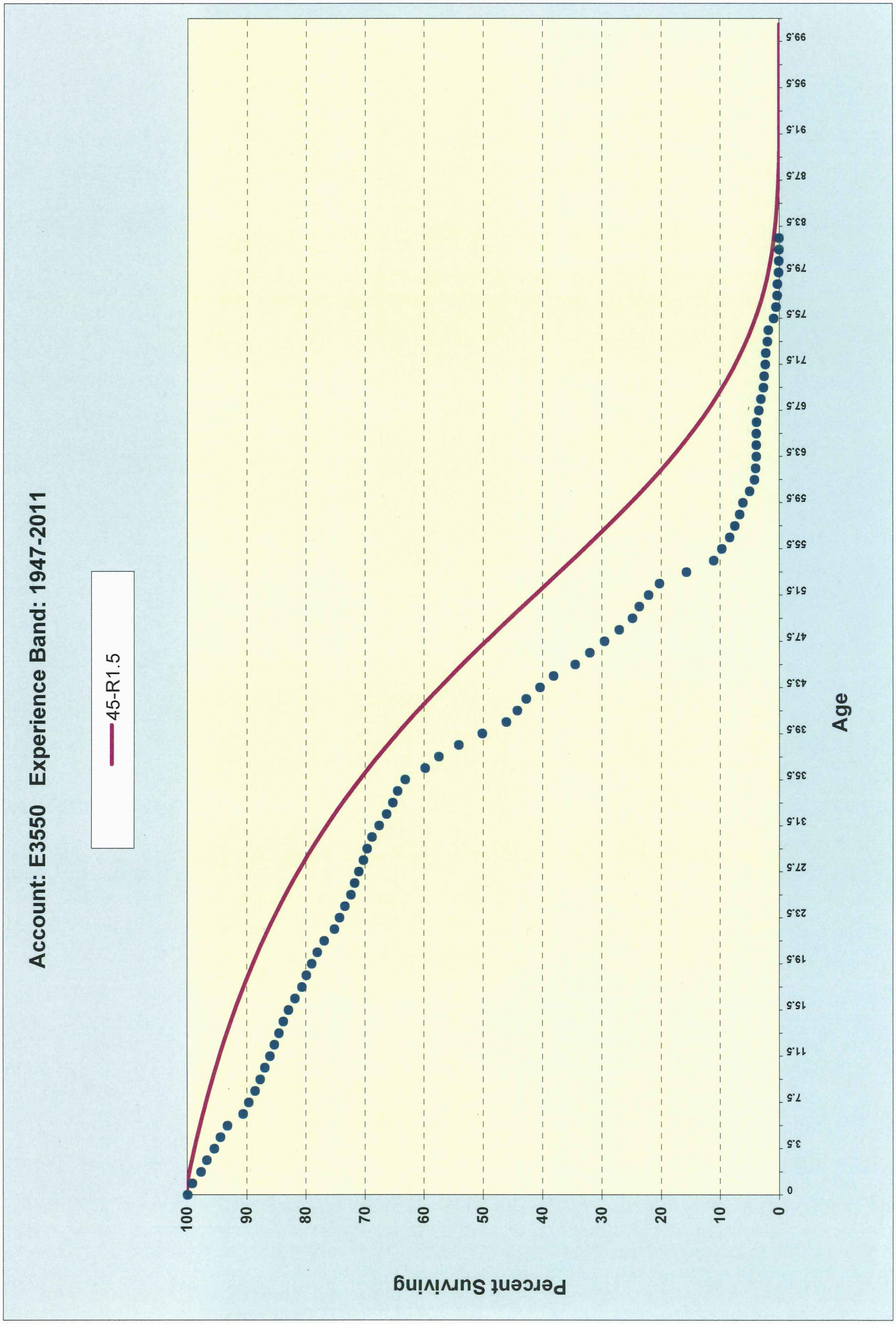
99.5

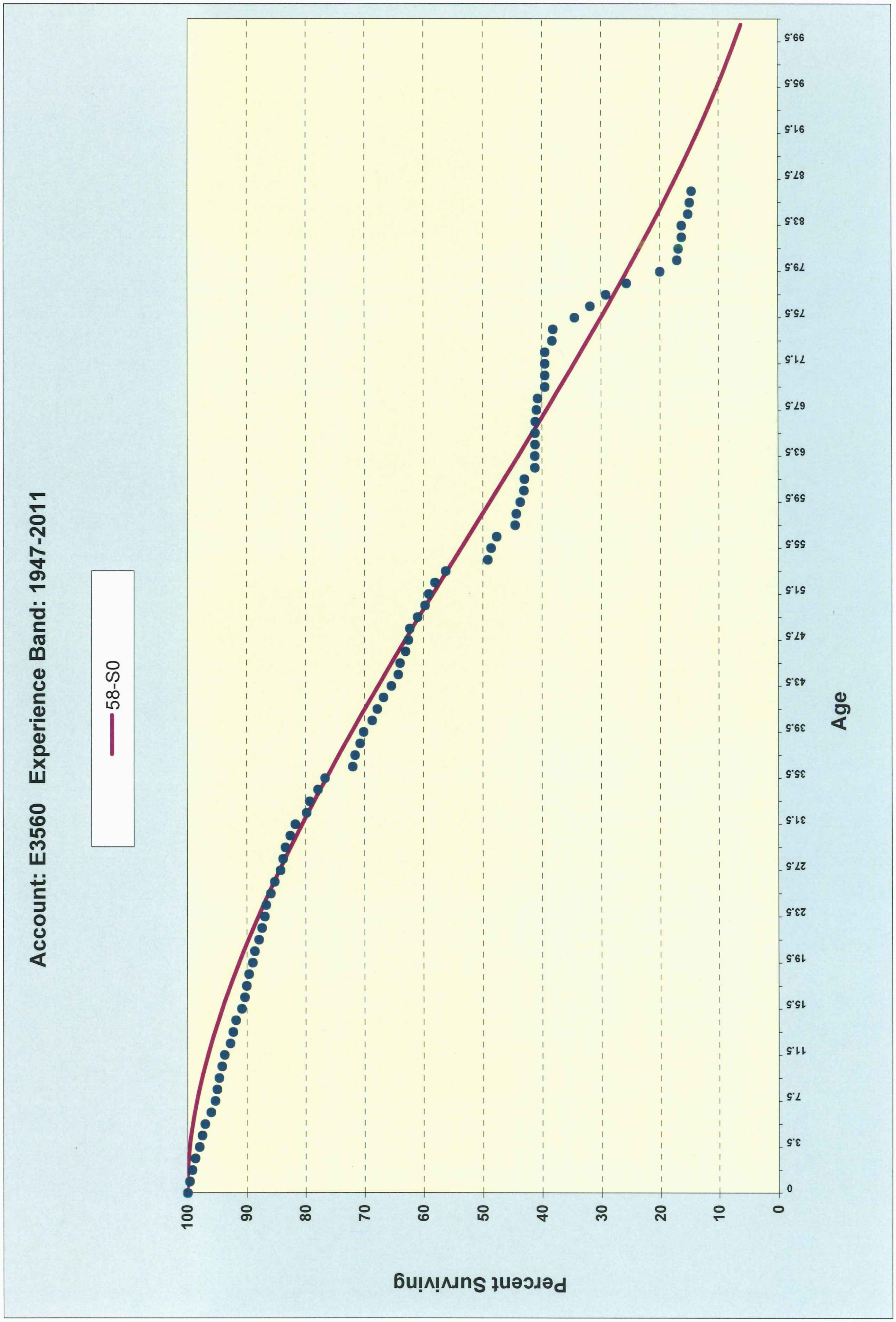

Account: E3550 Experience Band: 1947-2011
45-R1.5
Percent Surviving
Age

Account: E3550 Experience Band: 1947-2011
Observed Life Table (OLT)

Iowa Curve Type	Curve No.	Average Service Life	Sum of Squared Deviations
R1	22	37.67	751.076
R1.5	23	38.40	893.616
S0.5	4	38.49	1604.038
S0	3	37.84	1672.250
R0.5	21	36.94	1765.257
R2	24	38.98	1880.010
S1	5	39.03	2135.265
S-0.5	2	36.97	2412.615
S1.5	6	39.54	3025.269
L1.5	16	39.29	3229.539
R2.5	25	39.58	3447.589
L1	15	38.67	3475.308
L2	17	39.80	3677.287
SC	1	35.90	4001.118
L0.5	14	38.42	4379.963
S2	7	39.96	4493.495
L3	18	40.57	5658.696
R3	26	40.06	5812.697
L0	13	38.10	5933.652
S3	8	40.62	8160.725
L4	19	41.02	9986.856
R4	27	40.78	11133.807
S4	9	41.18	14054.291
L5	20	41.33	15952.548
R5	28	41.25	18609.603
S5	10	41.39	20539.889
S6	11	41.28	26867.570

Account: E3550 Experience Band: 1947-2011
Smoothed Life Table (SLT)

Iowa Curve Type	Curve No.	Average Service Life	Sum of Squared Deviations
R1	22	37.72	272.189
R1.5	23	38.45	621.361
S0	3	37.80	976.716
S0.5	4	38.46	1041.312
R0.5	21	36.90	1107.155
S-0.5	2	36.90	1634.551
S1	5	39.02	1697.257
R2	24	39.06	1809.595
L1.5	16	39.22	2534.103
L1	15	38.69	2678.490
S1.5	6	39.51	2789.459
L2	17	39.66	3090.429
SC	1	35.83	3110.395
L0.5	14	38.54	3482.639
R2.5	25	39.62	3657.470
S2	7	39.94	4461.546
L0	13	38.36	4903.727
L3	18	40.32	5524.948
R3	26	40.12	6315.146
S3	8	40.57	8653.442
L4	19	40.82	10718.108
R4	27	40.78	12219.362
S4	9	41.06	15308.576
L5	20	41.15	17471.113
R5	28	41.20	20404.093
S5	10	41.27	22543.809
S6	11	41.26	29488.465
SQ	12	39.32	42683.578


Account: E3560 Experience Band: 1947-2011
58-S0
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
Age
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
31.5
35.5
39.5
43.5
47.5
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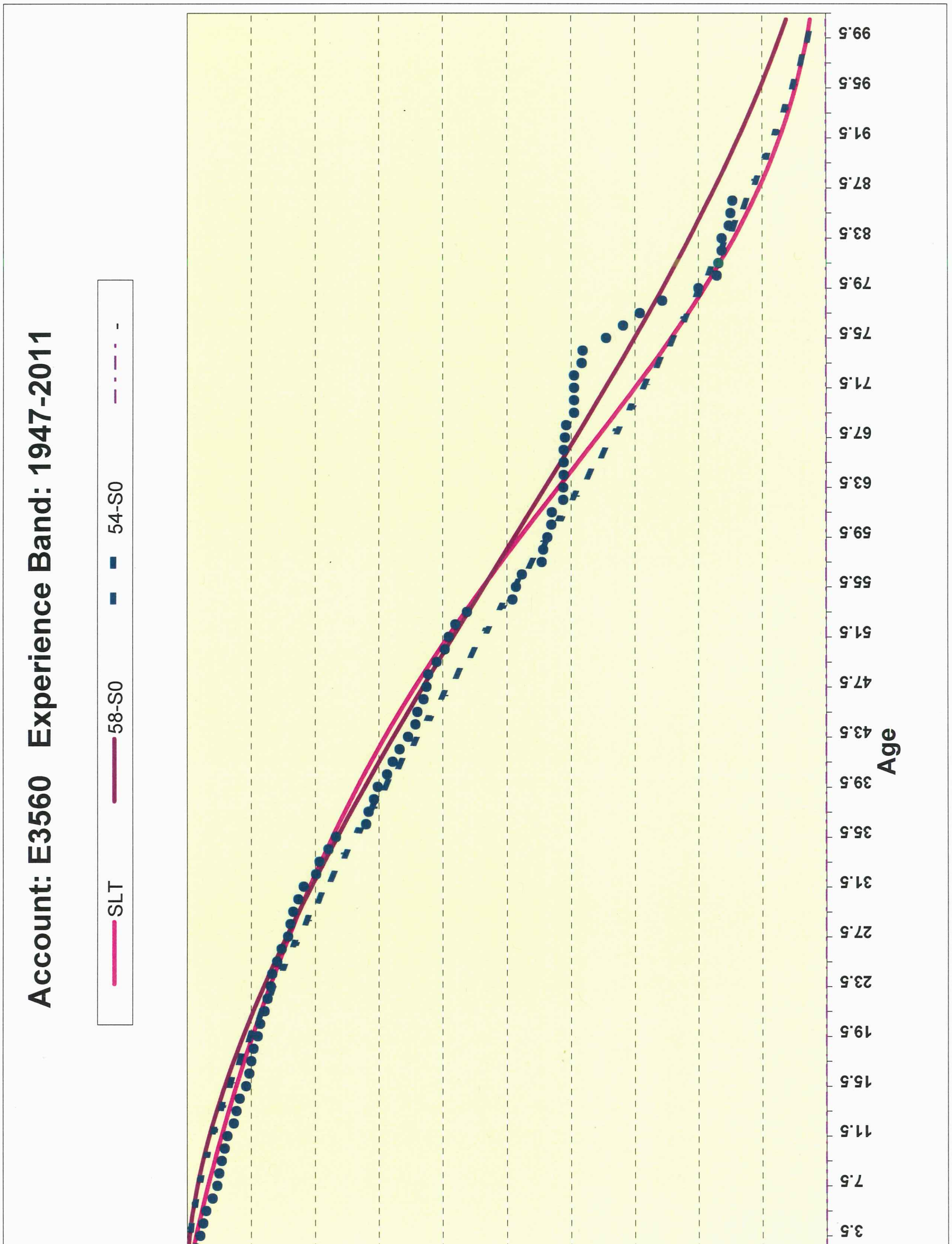
Account: E3560 Experience Band: 1947-2011
SLT
58-S0
54-S0
Percent Surviving
Age
100
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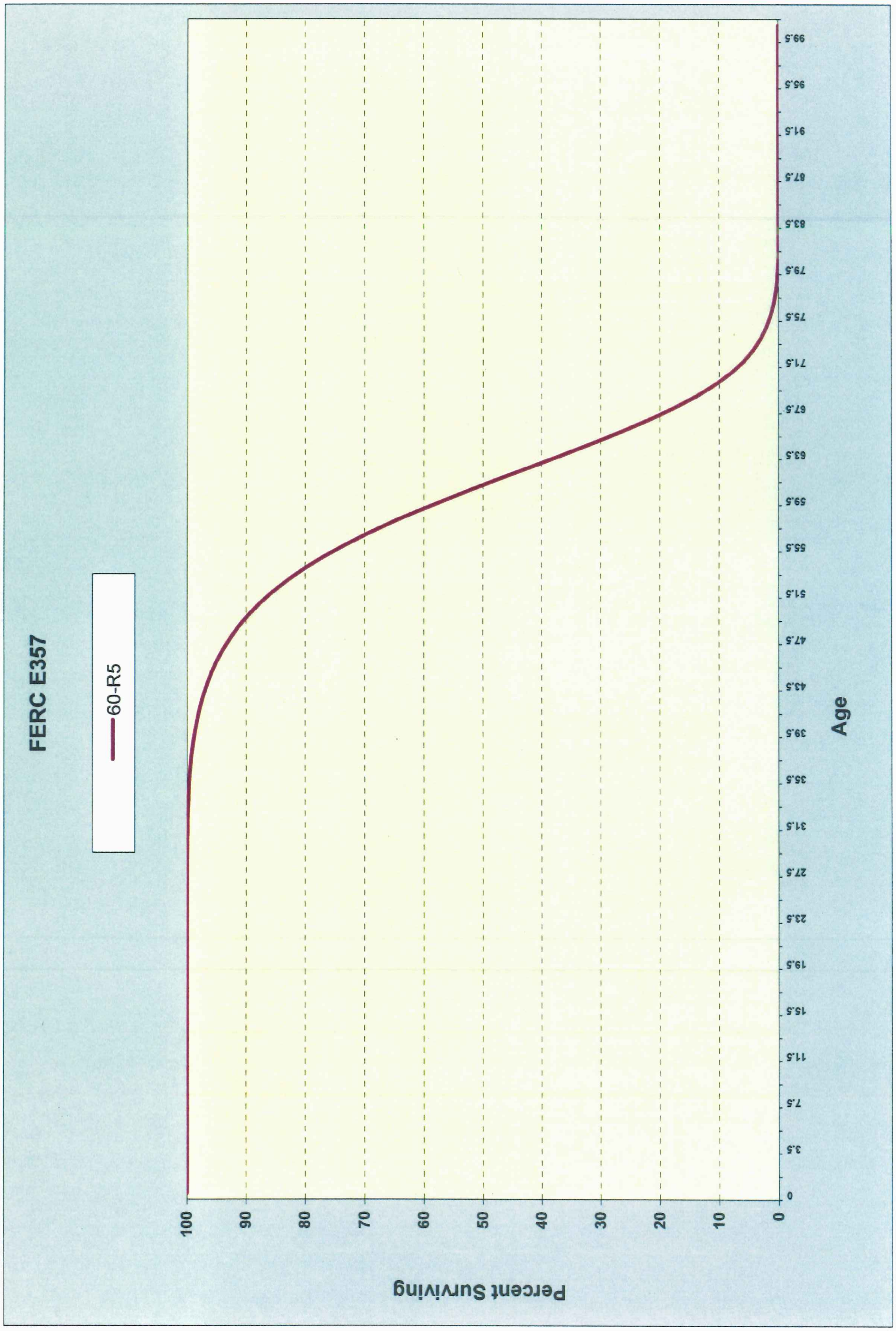
59.5
63.5
67.5
71.5
75.5
79.5
83.5
87.5
91.5
95.5
99.5

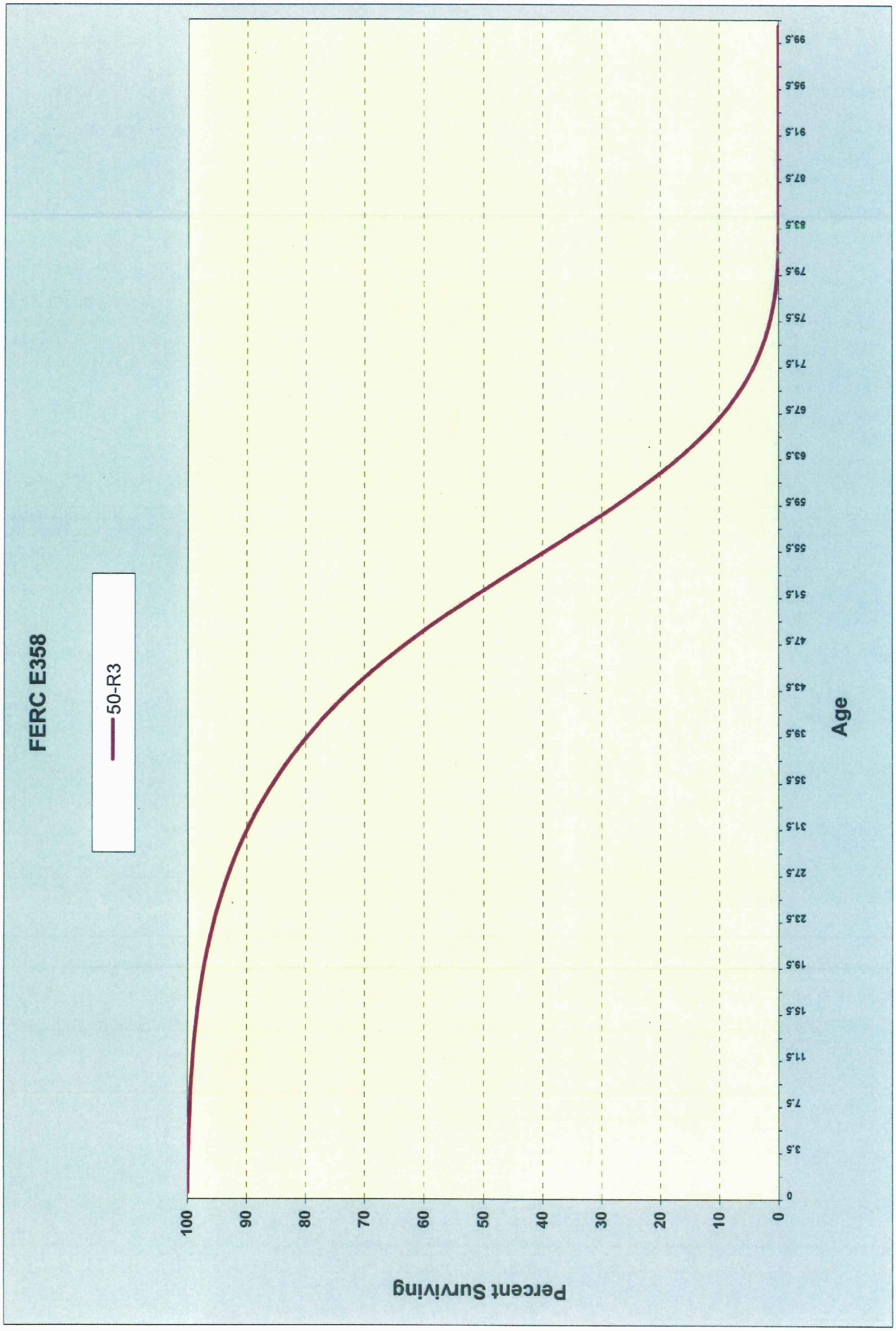
Account: E3560 Experience Band: 1947-2011
Observed Life Table (OLT)

Iowa Curve Type	Curve No.	Average Service Life	Sum of Squared Deviations
S0	3	58.35	769.633
R1	22	57.60	863.369
L1	15	61.01	1051.618
R0.5	21	57.45	1225.593
S0.5	4	58.74	1245.539
S-0.5	2	57.99	1290.379
L0.5	14	61.85	1357.982
L1.5	16	60.84	1444.364
R1.5	23	58.29	1864.851
L0	13	62.94	2351.866
S1	5	59.12	2571.153
L2	17	60.69	2835.602
SC	1	57.62	3093.293
R2	24	58.93	4043.868
S1.5	6	59.53	4670.253
R2.5	25	59.64	7450.952
S2	7	59.92	7598.777
L3	18	60.28	8286.876
R3	26	60.33	12034.171
S3	8	60.58	15137.957
L4	19	60.22	18514.618
R4	27	61.10	22644.698
S4	9	60.85	27279.278
L5	20	60.03	30701.945
R5	28	60.19	36964.369
S5	10	59.80	40085.781
S6	11	57.97	50934.632

Account: E3560 Experience Band: 1947-2011
Smoothed Life Table (SLT)

Iowa Curve Type	Curve No.	Average Service Life	Sum of Squared Deviations
R1	22	55.18	59.111
R1.5	23	56.08	337.726
S0.5	4	56.25	343.206
S0	3	55.43	534.806
S1	5	56.96	1077.164
R0.5	21	54.15	1415.659
L1.5	16	57.26	1781.613
R2	24	56.82	1929.142
S-0.5	2	54.22	1930.695
L2	17	57.82	2189.329
L1	15	56.55	2438.269
S1.5	6	57.52	2535.205
L0.5	14	56.29	4080.427
R2.5	25	57.46	4480.297
SC	1	52.81	4631.743
S2	7	57.98	4888.952
L3	18	58.51	5561.286
L0	13	55.92	6669.806
R3	26	58.00	8284.370
S3	8	58.59	11017.057
L4	19	58.83	13712.122
R4	27	58.62	16781.104
S4	9	58.92	20887.513
L5	20	58.96	23895.614
R5	28	58.85	28553.264
S5	10	58.89	31560.601
S6	11	58.63	41672.296
SQ	12	57.22	61181.995


FERC E357
60-R5
Percent Surviving
Age
100
90
80
70
60
50
40
30
20
10
0
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
31.5
35.5
39.5
43.5
47.5
51.5
55.5
59.5
63.5
67.5
71.5
75.5
79.5
83.5
87.5
91.5
95.5
99.5


FERC E358
50-R3
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
Age
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
31.5
35.5
39.5
43.5
47.5
51.5
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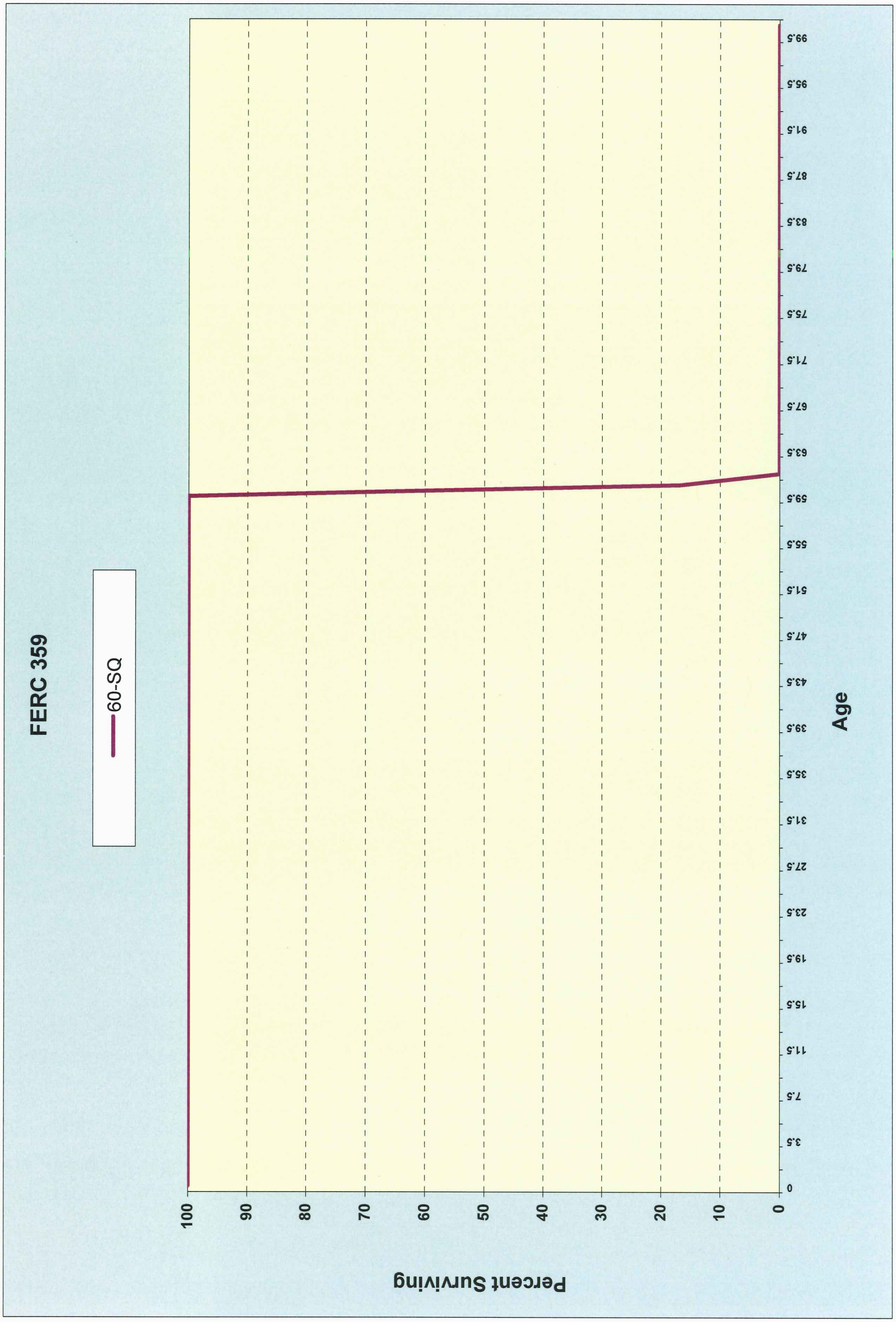
79.5
83.5
87.5
91.5
95.5
99.5


FERC 359
60-SQ
Percent Surviving
Age
100
90
80
70
60
50
40
30
20
10
0
0
3.5
7.5
11.5
15.5
19.5
23.5
27.5
31.5
35.5
39.5
43.5
47.5
51.5
55.5
59.5
63.5
67.5
71.5
75.5
79.5
83.5
87.5
91.5
95.5
99.5

APPENDIX “B”

FUTURE NET SALVAGE (FNS) STUDY DETAIL

TO4 ANALYSIS

SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC ACCOUNTS SUMMARY TABLE

	1991-2005			TO3 FERC Filing Detail for July 2007						
Account (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D)	COST OF REMOVAL (E)	% OF RFS (F)	NET SALVAGE (G)	% OF RFS (H)	CURRENT PLANT (I)	TO CURRENT PLANT (J)	% FNS Rounded to Nearest 5%
352.1	574,958	142,827	24.84	323,571	56.28	(180,744)	(31.44)	58,592,677	0.98%	-30%
352.2	6,400	0	0.00	742	11.59	(742)	(11.59)	10,189,341	0.06%	-10%
353.1	12,287,529	660,251	5.37	6,478,822	52.73	(5,818,571)	(47.35)	307,171,555	4.00%	-45%
353.2	2,493,362	4,160	0.17	1,030,528	41.33	(1,026,368)	(41.16)	138,776,308	1.80%	-40%
354.1	888,391	0	0.00	269,579	30.34	(269,579)	(30.34)	34,024,284	2.61%	-30%
354.2	0	0	0.00	0	0.00	0	0.00	61,988,482	0.00%	0%
355.1	10,847,386	76,797	0.71	8,492,091	78.29	(8,415,294)	(77.58)	95,277,179	11.39%	-80%
355.2	0	0	0.00	0	0.00	0	0.00	7,918,275	0.00%	0%
356.1	9,957,820	91,022	0.91	8,961,077	89.99	(8,870,055)	(89.08)	135,394,778	7.35%	-90%
356.2	508	0	0.00	0	0.00	0	0.00	42,153,628	0.00%	0%
357	286,969	23,394	8.15	149,597	52.13	(126,203)	(43.98)	40,817,077	0.70%	-45%
358	3,885,717	71,678	1.84	400,728	10.31	(329,050)	(8.47)	28,143,063	13.81%	-10%
359.1	12,581	0	0.00	38,106	302.89	(38,106)	(302.89)	10,071,163	0.12%	-305%
359.2	0	0	0.00	0	0.00	0	0.00	4,426,863	0.00%	0%
Totals	41,241,623	1,070,129	**2.59%**	26,144,841	63.39%	(25,074,712)	**-60.80%**	974,944,673	4.23%	-60%

SAN DIEGO GAS AND ELECTRIC COMPANY
ELECTRIC ACCOUNTS SUMMARY TABLE

	1997-2011			TO4 FERC Filing Detail for July 2013						
Account (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D)	COST OF REMOVAL (E)	% OF RFS (F)	NET SALVAGE (G)	% OF RFS (H)	CURRENT PLANT (I)	TO CURRENT PLANT (J)	% FNS Rounded to Nearest 5%
352.1	1,558,600	699,684	45	1,816,588	117	(1,116,904)	(71.66)	102,586,460	1.52%	-70%
352.2	475,025	0	0	297,349	63	(297,349)	(62.60)	10,354,490	4.59%	-65%
352.6	0	0	0	0	0	0	0.00	1,268,807	0.00%	0%
E352 Totals	2,033,624	699,684	34	2,131,858	105	(1,432,174)	(70.42)	114,209,757	1.78%	-70%
353.1	27,312,023	5,835,161	21	23,519,745	86	(17,684,584)	(64.75)	520,112,885	5.25%	-65%
353.2	8,291,638	4,960	0	5,063,765	61	(5,058,805)	(61.01)	171,254,190	4.84%	-60%
353.4	0 0	0	0	0	0	0	0.00	0	0.00%	0%
353.6	0	0	0	0	0	0	0.00	18,635,181	0.00%	0%
E353 Totals	35,603,661	5,840,121	16	28,583,511	80	(22,743,390)	(63.88)	710,002,256	5.01%	-65%
354.1	1,124,900	0	0	1,349,107	120	(1,349,107)	(119.93)	48,087,326	2.34%	-120%
354.2	0	0	0	0	0	0	0.00	61,988,482	0.00%	0%
354.6	0	0	0	0	0	0	0.00	111,180	0.00%	0%
E354 Totals	1,124,900	0	0	1,349,107	120	(1,349,107)	(119.93)	110,186,988	1.02%	-120%
355.1	22,850,123	41,999	0	24,333,805	106	(24,291,806)	(106.31)	223,792,702	10.21%	-105%
355.2	0	0	0	0	0	0	0.00	8,106,560	0.00%	0%
355.6	0	0	0	0	0	0	0.00	593,809	0.00%	0%
E355 Totals	22,850,123	41,999	0	24,333,805	106	(24,291,806)	(106.31)	232,493,071	9.83%	-105%
356.1	12,319,452	321,654	3	14,946,516	121	(14,624,862)	(118.71)	243,805,493	5.05%	-120%
356.2	508	0	0	0	0	0	0.00	42,153,628	0.00%	0%
356.6	0	0	0	0	0	0	0.00	1,612,791	0.00%	0%
E356 Totals	12,319,960	321,654	3	14,946,516	121	(14,624,862)	(118.71)	287,571,912	4.28%	-120%
357	163,392	0	0	145,729	89	(145,729)	(89.19)	136,576,747	0.12%	-90%
357.6	0	0	0	0	0	0	0.00	150,715	0.00%	0%
E357 Totals	163,392	0	0	145,729	89	(145,729)	(89.19)	136,727,462	0.12%	-90%
358	3,533,769	1,181	0	388,795	11	(387,614)	(10.97)	125,485,230	2.82%	-10%
358.6	0	0	0	0	0	0	0.00	307,441	0.00%	0%
E358 Totals	3,533,769	1,181	0	388,795	11	(387,614)	(10.97)	125,792,671	2.81%	-10%
359.1	8,811	0	0	258,024	2,928	(258,024)	(2,928.44)	29,438,496	0.03%	-2930%
359.2	0	0	0	0	0	0	0.00	4,426,863	0.00%	0%
359.6	0	0	0	0	0	0	0.00	177,218	0.00%	0%
E359 Totals	8,811	0	0	258,024	2,928	(258,024)	(2,928.44)	34,042,577	0.03%	-2930%
Totals	77,638,240	6,904,639	8.89%	72,137,344	92.91%	(65,232,705)	-84.02%	1,751,026,694	4.43%	-85%

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY

E-352 Totals

ACCOUNT - STRUCTURES & IMPROVEMENTS PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2005 (L)
1991	63,296	-	0.00	12,554	19.83	(12,554)	(19.83)				(31.22)
1992	62,850	-	0.00	20,025	31.86	(20,025)	(31.86)				(32.61)
1993	56,865	12,676	22.29	17,417	30.63	(4,741)	(8.34)				(32.71)
1994	41,189	-	0.00	20,194	49.03	(20,194)	(49.03)				(36.19)
1995	4,692	-	0.00	88	1.88	(88)	(1.88)			(25.17)	(34.71)
1996	14,291	-	0.00	23,583	165.02	(23,583)	(165.02)			(38.15)	(35.15)
1997	6,570	-	0.00	4,424	67.34	(4,424)	(67.34)			(42.90)	(29.66)
1998	9,710	-	0.00	6,470	66.63	(6,470)	(66.63)			(71.63)	(28.91)
1999	3,419	-	0.00	3,224	94.28	(3,224)	(94.28)			(97.69)	(27.78)
2000	152,000	130,151	85.63	6,425	4.23	123,726	81.40			46.25	(27.06)
2001	-	-	0.00	147,335	0.00	(147,335)	0.00			(21.97)	(126.09)
2002	8,463	-	0.00	5,922	69.97	(5,922)	(69.97)			(22.60)	(37.59)
2003	-	-	0.00	-	0.00	-	0.00			(19.99)	(35.85)
2004	3,175	-	0.00	3,448	108.60	(3,448)	(108.60)			(20.15)	(35.85)
2005	154,838	-	0.00	53,204	34.36	(53,204)	(34.36)	68,782,018	0.23%	(126.09)	(34.36)
TOTALS	581,358	142,827	24.57	324,313	55.79	(181,486)	(31.22)	68,782,018	0.85%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

E-352 Totals

ACCOUNT - STRUCTURES & IMPROVEMENTS PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	6,570	-	0.00	4,424	67.34	(4,424)	(67.34)				(70.42)
1998	9,710	-	0.00	6,470	66.63	(6,470)	(66.63)				(70.43)
1999	3,419	-	0.00	3,224	94.28	(3,224)	(94.28)				(70.45)
2000	152,000	130,151	85.63	6,425	4.23	123,726	81.40				(70.41)
2001	-	-	0.00	147,335	0.00	(147,335)	0.00			(21.97)	(82.81)
2002	8,463	-	0.00	5,922	69.97	(5,922)	(69.97)			(22.60)	(74.89)
2003	-	-	0.00	-	0.00	-	0.00			(19.99)	(74.92)
2004	3,175	-	0.00	3,448	108.60	(3,448)	(108.60)			(20.15)	(74.92)
2005	154,838	-	0.00	53,204	34.36	(53,204)	(34.36)	68,782,018	0.23%	(126.09)	(74.86)
2006	62,672	-	0.00	22,875	36.50	(22,875)	(36.50)	75,376,719	0.08%	(37.29)	(78.56)
2007	368,196	-	0.00	47,539	12.91	(47,539)	(12.91)	80,918,914	0.46%	(21.58)	(80.17)
2008	148,523	-	0.00	500,748	337.15	(500,748)	(337.15)	95,041,076	0.16%	(85.14)	(99.75)
2009	153,642	-	0.00	716,990	466.66	(716,990)	(466.66)	98,525,957	0.16%	(151.08)	(68.16)
2010	874,882	-	0.00	282,336	32.27	(282,336)	(32.27)	100,004,027	0.87%	(97.67)	(4.54)
2011	87,534	569,533	650.64	330,918	378.05	238,615	272.60	114,209,757	0.08%	(80.17)	272.60
TOTAL (15)	2,033,624	699,684	34.41	2,131,858	104.83	(1,432,174)	(70.42)	114,209,757	1.78%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-352.1**
ACCOUNT - STRUCTURES & IMPROVEMENTS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	63,296	-	0.00	12,554	19.83	(12,554)	(19.83)				(31.44)
1992	62,850	-	0.00	20,025	31.86	(20,025)	(31.86)				(32.87)
1993	56,865	12,676	22.29	17,417	30.63	(4,741)	(8.34)				(33.01)
1994	41,189	-	0.00	20,194	49.03	(20,194)	(49.03)				(36.59)
1995	4,692	-	0.00	88	1.88	(88)	(1.88)			(25.17)	(35.13)
1996	10,091	-	0.00	22,841	226.35	(22,841)	(226.35)			(38.64)	(35.58)
1997	6,570	-	0.00	4,424	67.34	(4,424)	(67.34)			(43.79)	(29.85)
1998	7,510	-	0.00	6,470	86.16	(6,470)	(86.16)			(77.11)	(29.11)
1999	3,419	-	0.00	3,224	94.28	(3,224)	(94.28)			(114.76)	(27.78)
2000	152,000	130,151	85.63	6,425	4.23	123,726	81.40			48.31	(27.06)
2001	-	-	0.00	147,335	0.00	(147,335)	0.00			(22.26)	(126.09)
2002	8,463	-	0.00	5,922	69.97	(5,922)	(69.97)			(22.89)	(37.59)
2003	-	-	0.00	-	0.00	-	0.00			(19.99)	(35.85)
2004	3,175	-	0.00	3,448	108.60	(3,448)	(108.60)			(20.15)	(35.85)
2005	154,838	-	0.00	53,204	34.36	(53,204)	(34.36)	58,592,677	0.26%	(126.09)	(34.36)
TOTALS	574,958	142,827	24.84	323,571	56.28	(180,744)	(31.44)	58,592,677	0.98%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-352.1**
ACCOUNT - STRUCTURES & IMPROVEMENTS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	6,570	-	0.00	4,424	67.34	(4,424)	(67.34)				(71.66)
1998	7,510	-	0.00	6,470	86.16	(6,470)	(86.16)				(71.68)
1999	3,419	-	0.00	3,224	94.28	(3,224)	(94.28)				(71.61)
2000	152,000	130,151	85.63	6,425	4.23	123,726	81.40				(71.56)
2001	-	-	0.00	147,335	0.00	(147,335)	0.00			(22.26)	(88.30)
2002	8,463	-	0.00	5,922	69.97	(5,922)	(69.97)			(22.89)	(77.69)
2003	-	-	0.00	-	0.00	-	0.00			(19.99)	(77.74)
2004	3,175	-	0.00	3,448	108.60	(3,448)	(108.60)			(20.15)	(77.74)
2005	154,838	-	0.00	53,204	34.36	(53,204)	(34.36)	58,592,677	0.26%	(126.09)	(77.67)
2006	36,680	-	0.00	19,335	52.71	(19,335)	(52.71)	65,213,120	0.06%	(40.32)	(83.15)
2007	161,429	-	0.00	29,617	18.35	(29,617)	(18.35)	70,962,081	0.23%	(29.65)	(84.09)
2008	148,523		0.00	426,255	287.00	(426,255)	(287.00)	85,023,451	0.17%	(105.39)	(94.45)
2009	146,263	-	0.00	708,540	484.43	(708,540)	(484.43)	88,012,726	0.17%	(190.97)	(61.80)
2010	642,196	-	0.00	99,694	15.52	(99,694)	(15.52)	89,527,351	0.72%	(113.07)	22.90
2011	87,534	569,533	650.64	302,695	345.80	266,838	304.84	102,586,460	0.09%	(84.09)	304.84
TOTALS	1,558,600	699,684	44.89	1,816,588	116.55	(1,116,904)	(71.66)	102,586,460	1.52%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-352.2**
ACCOUNT - STRUCTURES & IMPROVEMENTS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	-	0.00	-	0.00				(11.59)
1992	-	-	0.00	-	0.00	-	0.00				(11.59)
1993	-	-	0.00	-	0.00	-	0.00				(11.59)
1994	-	-	0.00	-	0.00	-	0.00				(11.59)
1995	-	-	0.00	-	0.00	-	0.00			NA	(11.59)
1996	4,200	-	0.00	742	17.66	(742)	(17.66)			(17.66)	(11.59)
1997	-	-	0.00	-	0.00	-	0.00			(17.66)	-
1998	2,200	-	0.00	-	0.00	-	0.00			(11.59)	-
1999	-	-	0.00	-	0.00	-	0.00			(11.59)	NA
2000	-	-	0.00	-	0.00	-	0.00			(11.59)	NA
2001	-	-	0.00	-	0.00	-	0.00			-	NA
2002	-	-	0.00	-	0.00	-	0.00			-	NA
2003	-	-	0.00	-	0.00	-	0.00			NA	NA
2004	-	-	0.00	-	0.00	-	0.00			NA	NA
2005	-	-	0.00	-	0.00	-	0.00	10,189,341	0.00%	NA	NA
TOTALS	6,400	-	0.00	742	11.59	(742)	(11.59)	10,189,341	0.06%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-352.2**
ACCOUNT - STRUCTURES & IMPROVEMENTS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	-	0.00	-	0.00				(62.60)
1998	2,200	-	0.00	-	0.00	-	0.00				(62.60)
1999	-	-	0.00	-	0.00	-	0.00				(62.89)
2000	-	-	0.00	-	0.00	-	0.00				(62.89)
2001	-	-	0.00	-	0.00	-	0.00			-	(62.89)
2002	-	-	0.00	-	0.00	-	0.00			-	(62.89)
2003	-	-	0.00	-	0.00	-	0.00			NA	(62.89)
2004	-	-	0.00	-	0.00	-	0.00			NA	(62.89)
2005	-	-	0.00	-	0.00	-	0.00	10,189,341	0.00%	NA	(62.89)
2006	25,992	-	0.00	3,540	13.62	(3,540)	(13.62)	10,163,599	0.26%	(13.62)	(62.89)
2007	206,767	-		-	0.00	-	0.00	9,956,833	2.08%	(1.52)	(65.75)
2008	-	-		74,493	0.00	(74,493)	0.00	10,017,625	0.00%	(33.53)	(122.39)
2009	7,379	-		8,450	114.51	(8,450)	(114.51)	10,513,231	0.07%	(36.01)	(91.36)
2010	232,687	-	0.00	182,642	78.49	(182,642)	(78.49)	10,257,137	2.27%	(56.92)	(90.62)
2011	-	-	0.00	28,224	0.00	(28,224)	0.00	10,354,490	0.00%	(65.75)	NA
TOTALS	475,025	-	0.00	297,349	62.60	(297,349)	(62.60)	10,354,490	4.59%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-352.60

ACCOUNT - Sunrise STRUCTURES AND IMPROVEMENTS - SRPL PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAI FNS % (K)	SHRINKING BAND INS % @2011 (L)
2010	-	-	0.00	-	0.00	-	0.00	219,539	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	1,268,807	0.00%	NA	NA
TOTAL (2)	-	-	0.00	-	0.00	-	0.00	1,268,807	0.00%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY

E-353 Totals

ACCOUNT - STATION EQUIPMENT   PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	1,867,476	41,903	2.24	373,394	19.99	(331,491)	(17.75)				(46.31)
1992	269,183	99,669	37.03	71,325	26.50	28,344	10.53				(50.44)
1993	797,673	88,966	11.15	178,438	22.37	(89,472)	(11.22)				(51.74)
1994	439,382	76,179	17.34	34,179	7.78	42,000	9.56				(54.47)
1995	773,685	193,776	25.05	77,299	9.99	116,477	15.05			(5.65)	(56.93)
1996	138,398	-	0.00	65,582	47.39	(65,582)	(47.39)			1.31	(62.17)
1997	186,457	103,115	55.30	138,803	74.44	(35,688)	(19.14)			(1.38)	(62.36)
1998	281,908	-	0.00	47,873	16.98	(47,873)	(16.98)			0.51	(63.15)
1999	74,153	-	0.00	198,811	268.11	(198,811)	(268.11)			(15.91)	(64.44)
2000	-	-	0.00	869,635	0.00	(869,635)	0.00			(178.82)	(62.93)
2001	124,962	-	0.00	142,850	114.31	(142,850)	(114.31)			(193.99)	(54.19)
2002	1,509,152	40,048	2.65	1,696,730	112.43	(1,656,683)	(109.78)			(146.51)	(53.42)
2003	1,268,551	20,005	1.58	594,818	46.89	(574,813)	(45.31)			(115.65)	(43.20)
2004	2,647,753	750	0.03	745,475	28.15	(744,725)	(28.13)			(71.86)	(42.82)
2005	4,402,159	-	0.00	2,274,139	51.66	(2,274,139)	(51.66)	445,947,863	0.99%	(54.19)	(51.66)
TOTALS	14,780,892	664,411	4.50	7,509,351	50.80	(6,844,940)	(46.31)	445,947,863	3.31%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

E-353 Totals

ACCOUNT - STATION EQUIPMENT   PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	186,457	103,115	55.30	138,803	74.44	(35,688)	(19.14)				(63.88)
1998	281,908	-	0.00	47,873	16.98	(47,873)	(16.98)				(64.11)
1999	74,153	-	0.00	198,811	268.11	(198,811)	(268.11)				(64.49)
2000	-	-	0.00	869,635	0.00	(869,635)	0.00				(64.06)
2001	124,962	-	0.00	142,850	114.31	(142,850)	(114.31)			(193.99)	(61.58)
2002	1,509,152	40,048	2.65	1,696,730	112.43	(1,656,683)	(109.78)			(146.51)	(61.39)
2003	1,268,551	20,005	1.58	594,818	46.89	(574,813)	(45.31)			(115.65)	(59.21)
2004	2,647,753	750	0.03	745,475	28.15	(744,725)	(28.13)			(71.86)	(59.76)
2005	4,402,159	-	0.00	2,274,139	51.66	(2,274,139)	(51.66)	445,947,863	0.99%	(54.19)	(62.60)
2006	7,600,326	-	0.00	2,165,630	28.49	(2,165,630)	(28.49)	499,678,835	1.52%	(42.55)	(64.51)
2007	4,477,291	2,572,961	57.47	969,952	21.66	1,603,009	35.80	521,019,280	0.86%	(20.38)	(80.15)
2008	996,899	-	0.00	2,046,552	205.29	(2,046,552)	(205.29)	597,742,019	0.17%	(27.97)	(119.99)
2009	1,447,716	870,366	60.12	4,008,949	276.92	(3,138,583)	(216.80)	633,128,164	0.23%	(42.39)	(112.92)
2010	7,677,945	-	0.00	5,979,990	77.89	(5,979,990)	(77.89)	662,721,941	1.16%	(52.83)	(98.72)
2011	2,908,389	2,232,876	76.77	6,703,304	230.48	(4,470,428)	(153.71)	710,002,256	0.41%	(80.15)	(153.71)
TOTAL (15)	35,603,661	5,840,121	16.40	28,583,511	80.28	(22,743,390)	(63.88)	710,002,256	0.05		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-353.1**
ACCOUNT - STATION EQUIPMENT PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	1,867,476	41,903	2.24	373,394	19.99	(331,491)	(17.75)				(47.35)
1992	269,183	99,669	37.03	71,325	26.50	28,344	10.53				(52.66)
1993	797,673	88,966	11.15	178,438	22.37	(89,472)	(11.22)				(54.33)
1994	439,382	76,179	17.34	34,179	7.78	42,000	9.56				(58.01)
1995	760,552	193,776	25.48	77,299	10.16	116,477	15.31			(5.66)	(61.34)
1996	138,398	-	0.00	65,582	47.39	(65,582)	(47.39)			1.32	(68.49)
1997	173,945	98,956	56.89	126,161	72.53	(27,206)	(15.64)			(1.03)	(68.86)
1998	270,817	-	0.00	47,873	17.68	(47,873)	(17.68)			1.00	(70.04)
1999	74,153	-	0.00	198,811	268.11	(198,811)	(268.11)			(15.73)	(71.91)
2000	-	-	0.00	826,384	0.00	(826,384)	0.00			(177.37)	(69.97)
2001	68,917	-	0.00	133,480	193.68	(133,480)	(193.68)			(209.88)	(58.95)
2002	1,112,720	40,048	3.60	1,500,599	134.86	(1,460,552)	(131.26)			(174.71)	(57.70)
2003	1,268,551	20,005	1.58	594,818	46.89	(574,813)	(45.31)			(126.53)	(44.73)
2004	2,033,082	750	0.04	729,093	35.86	(728,343)	(35.82)			(83.05)	(44.59)
2005	3,012,681	-	0.00	1,521,386	50.50	(1,521,386)	(50.50)	307,171,555	0.98%	(58.95)	(50.50)
TOTALS	12,287,529	660,251	5.37	6,478,822	52.73	(5,818,571)	(47.35)	307,171,555	4.00%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-353.1**
ACCOUNT - STATION EQUIPMENT PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	173,945	98,956	56.89	126,161	72.53	(27,206)	(15.64)				(64.75)
1998	270,817	-	0.00	47,873	17.68	(47,873)	(17.68)				(65.06)
1999	74,153	-	0.00	198,811	268.11	(198,811)	(268.11)				(65.54)
2000	-	-	0.00	826,384	0.00	(826,384)	0.00				(64.98)
2001	68,917	-	0.00	133,480	193.68	(133,480)	(193.68)			(209.88)	(61.90)
2002	1,112,720	40,048	3.60	1,500,599	134.86	(1,460,552)	(131.26)			(174.71)	(61.56)
2003	1,268,551	20,005	1.58	594,818	46.89	(574,813)	(45.31)			(126.53)	(58.53)
2004	2,033,082	750	0.04	729,093	35.86	(728,343)	(35.82)			(83.05)	(59.22)
2005	3,012,681	-	0.00	1,521,386	50.50	(1,521,386)	(50.50)	307,171,555	0.98%	(58.95)	(61.35)
2006	4,729,864	-	0.00	1,781,925	37.67	(1,781,925)	(37.67)	341,023,965	1.39%	(49.91)	(63.04)
2007	4,202,297	2,572,961	61.23	777,923	18.51	1,795,038	42.72	361,541,961	1.16%	(18.44)	(71.28)
2008	987,672	-	0.00	1,997,619	202.26	(1,997,619)	(202.26)	434,952,541	0.23%	(28.29)	(117.50)
2009	1,362,298	870,366	63.89	3,712,389	272.51	(2,842,023)	(208.62)	461,765,086	0.30%	(44.41)	(108.57)
2010	6,324,292	-	0.00	4,939,348	78.10	(4,939,348)	(78.10)	491,554,048	1.29%	(55.47)	(91.57)
2011	1,690,735	2,232,076	132.02	4,631,936	273.96	(2,399,860)	(141.94)	520,112,885	0.33%	(71.28)	(141.94)
TOTAL (15)	27,312,023	5,835,161	21.36	23,519,745	86.11	(17,684,584)	(64.75)	520,112,885	5.25%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-353.2
ACCOUNT - STATION EQUIPMENT PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	-	0.00	-	0.00				(41.16)
1992	-	-	0.00	-	0.00	-	0.00				(41.16)
1993	-	-	0.00	-	0.00	-	0.00				(41.16)
1994	-	-	0.00	-	0.00	-	0.00				(41.16)
1995	13,133	-	0.00	-	0.00	-	0.00			-	(41.16)
1996	-	-	0.00	-	0.00	-	0.00			-	(41.38)
1997	12,512	4,160	33.25	12,642	101.04	(8,482)	(67.79)			(33.07)	(41.38)
1998	11,091	-	0.00	-	0.00	-	0.00			(23.09)	(41.25)
1999	-	-	0.00	-	0.00	-	0.00			(23.09)	(41.43)
2000	-	-	0.00	43,251	0.00	(43,251)	0.00			(219.18)	(41.43)
2001	56,045	-	0.00	9,370	16.72	(9,370)	(16.72)			(76.72)	(39.67)
2002	396,432	-	0.00	196,131	49.47	(196,131)	(49.47)			(53.66)	(40.21)
2003	-	-	0.00	-	0.00	-	0.00			(54.98)	(38.38)
2004	614,671	-	0.00	16,382	2.67	(16,382)	(2.67)			(24.85)	(38.38)
2005	1,389,478	-	0.00	752,753	54.18	(752,753)	(54.18)	138,776,308	1.00%	(39.67)	(54.18)
TOTALS	2,493,362	4,160	0.17	1,030,528	41.33	(1,026,368)	(41.16)	138,776,308	1.80%		

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SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-353.2
ACCOUNT - STATION EQUIPMENT PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	12,512	4,160	33.25	12,642	101.04	(8,482)	(67.79)				(61.01)
1998	11,091	-	0.00	-	0.00	-	0.00				(61.00)
1999	-	-	0.00	-	0.00	-	0.00				(61.08)
2000	-	-	0.00	43,251	0.00	(43,251)	0.00				(61.08)
2001	56,045	-	0.00	9,370	16.72	(9,370)	(16.72)			(76.72)	(60.56)
2002	396,432	-	0.00	196,131	49.47	(196,131)	(49.47)			(53.66)	(60.86)
2003	-	-	0.00	-	0.00	-	0.00			(54.98)	(61.44)
2004	614,671	-	0.00	16,382	2.67	(16,382)	(2.67)			(24.85)	(61.44)
2005	1,389,478	-	0.00	752,753	54.18	(752,753)	(54.18)	138,776,308	1.00%	(39.67)	(66.45)
2006	2,870,462	-	0.00	383,705	13.37	(383,705)	(13.37)	158,654,870	1.81%	(25.59)	(69.39)
2007	274,994	-	0.00	192,029	69.83	(192,029)	(69.83)	159,477,319	0.17%	(26.12)	(124.07)
2008	9,227	-	0.00	48,933	530.32	(48,933)	(530.32)	162,789,478	0.01%	(27.02)	(129.66)
2009	85,418	-	0.00	296,560	347.19	(296,560)	(347.19)	171,363,078	0.05%	(36.16)	(128.27)
2010	1,353,654	-	0.00	1,040,642	76.88	(1,040,642)	(76.88)	169,255,118	0.80%	(42.71)	(121.00)
2011	1,217,655	800	0.07	2,071,368	170.11	(2,070,568)	(170.05)	171,254,190	0.71%	(124.07)	(170.05)
TOTAL (15)	8,291,638	4,960	0.06	5,063,765	61.07	(5,058,805)	(61.01)	171,254,190	4.84%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-353.4 (Palomar)

ACCOUNT - STATION EQUIPMENT PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
2007	-	-	0.00	-	0.00	-	0.00	1,600,000	0.00%	NA	NA
2008	-	-	0.00	-	0.00	-	0.00	1,600,000	0.00%	NA	NA
2009	-	-	0.00	-	0.00	-	0.00	1,600,000	0.00%	NA	NA
2010	-	-	0.00	-	0.00	-	0.00	1,600,000	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	1,600,000	0.00%	NA	NA
TOTAL (5)	-	-	0.00	-	#DIV/0!	-	#DIV/0!	1,600,000	0.00%		

TO4 FERC

SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-353.60

ACCOUNT - Sunrise STATION EQUIPMENT - SRPL PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAI FNS % (K)	SHRINKING BAND INS % @2011 (L)
2010	-	-	0.00	-	0.00	-	0.00	1,912,775		NA	NA
2011	-	-	0.00	-	0.00	-	0.00	18,635,181		NA	NA
TOTAL (2)	-	-	0.00	-	0.00	-	0.00	18,635,181	0.00%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY

E-354 Totals

ACCOUNT - TOWERS & FIXTURES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	57,786	-	0.00	6,142	10.63	(6,142)	(10.63)				(30.34)
1992	-	-	0.00	20	0.00	(20)	0.00				(31.72)
1993	-	-	0.00	1,397	0.00	(1,397)	0.00				(31.71)
1994	-	-	0.00	237	0.00	(237)	0.00				(31.55)
1995	17,909	-	0.00	89	0.50	(89)	(0.50)			(10.42)	(31.52)
1996	9,652	-	0.00	43,573	451.44	(43,573)	(451.44)			(164.42)	(32.20)
1997	74,166	-	0.00	22,876	30.84	(22,876)	(30.84)			(67.01)	(27.16)
1998	64,024	-	0.00	22,369	34.94	(22,369)	(34.94)			(53.78)	(26.79)
1999	73,660	-	0.00	10,904	14.80	(10,904)	(14.80)			(41.69)	(26.00)
2000	-	-	0.00	21,515	0.00	(21,515)	0.00			(54.73)	(27.40)
2001	18,840	-	0.00	16,155	85.75	(16,155)	(85.75)			(40.67)	(23.76)
2002	-	-	0.00	-	0.00	-	0.00			(45.32)	(21.72)
2003	-	-	0.00	-	0.00	-	0.00			(52.51)	(21.72)
2004	27,604	-	0.00	109,131	395.34	(109,131)	(395.34)			(316.08)	(21.72)
2005	544,750	-	0.00	15,171	2.78	(15,171)	(2.78)	96,012,766	0.57%	(23.76)	(2.78)
TOTALS	888,391	-	0.00	269,579	30.34	(269,579)	(30.34)	96,012,766	0.93%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

E-354 Totals

ACCOUNT - TOWERS & FIXTURES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	74,166	-	0.00	22,876	30.84	(22,876)	(30.84)				(119.93)
1998	64,024	-	0.00	22,369	34.94	(22,369)	(34.94)				(126.22)
1999	73,660	-	0.00	10,904	14.80	(10,904)	(14.80)				(132.14)
2000	-	-	0.00	21,515	0.00	(21,515)	0.00				(141.61)
2001	18,840	-	0.00	16,155	85.75	(16,155)	(85.75)			(40.67)	(139.25)
2002	-	-	0.00	-	0.00	-	0.00			(45.32)	(140.38)
2003	-	-	0.00	-	0.00	-	0.00			(52.51)	(140.38)
2004	27,604	-	0.00	109,131	395.34	(109,131)	(395.34)			(316.08)	(140.38)
2005	544,750	-	0.00	15,171	2.78	(15,171)	(2.78)	96,012,766	0.57%	(23.76)	(132.26)
2006	-	-	0.00	-	0.00	-	0.00	102,233,924	0.00%	(21.72)	(351.40)
2007	17,203	-	0.00	24,346	141.52	(24,346)	(141.52)	104,682,106	0.02%	(25.21)	(351.40)
2008	47,688	-	0.00	155,138	325.32	(155,138)	(325.32)	108,000,168	0.04%	(47.67)	(363.25)
2009	249,646	-	0.00	768,892	307.99	(768,892)	(307.99)	107,855,852	0.23%	(112.13)	(370.28)
2010	3,645	-	0.00	136,428	3,742.88	(136,428)	(3,742.88)	109,042,382	0.00%	(340.94)	(2,495.04)
2011	3,674	-	0.00	46,183	1,257.03	(46,183)	(1,257.03)	110,186,988	0.00%	(351.40)	(1,257.03)
TOTAL (15)	1,124,900	-	0.00	1,349,107	119.93	(1,349,107)	(119.93)	110,186,988	1.02%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-354.1**
ACCOUNT - TOWERS & FIXTURES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	57,786	-	0.00	6,142	10.63	(6,142)	(10.63)				(30.34)
1992	-	-	0.00	20	0.00	(20)	0.00				(31.72)
1993	-	-	0.00	1,397	0.00	(1,397)	0.00				(31.71)
1994	-	-	0.00	237	0.00	(237)	0.00				(31.55)
1995	17,909	-	0.00	89	0.50	(89)	(0.50)			(10.42)	(31.52)
1996	9,652	-	0.00	43,573	451.44	(43,573)	(451.44)			(164.42)	(32.20)
1997	74,166	-	0.00	22,876	30.84	(22,876)	(30.84)			(67.01)	(27.16)
1998	64,024	-	0.00	22,369	34.94	(22,369)	(34.94)			(53.78)	(26.79)
1999	73,660	-	0.00	10,904	14.80	(10,904)	(14.80)			(41.69)	(26.00)
2000	-	-	0.00	21,515	0.00	(21,515)	0.00			(54.73)	(27.40)
2001	18,840	-	0.00	16,155	85.75	(16,155)	(85.75)			(40.67)	(23.76)
2002	-	-	0.00	-	0.00	-	0.00			(45.32)	(21.72)
2003	-	-	0.00	-	0.00	-	0.00			(52.51)	(21.72)
2004	27,604	-	0.00	109,131	395.34	(109,131)	(395.34)			(316.08)	(21.72)
2005	544,750	-	0.00	15,171	2.78	(15,171)	(2.78)	34,024,284	1.60%	(23.76)	(2.78)
Totals	**888,391**	-	**0.00**	**269,579**	**30.34**	**(269,579)**	**(30.34)**	34,024,284	2.61%		

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SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-354.1**
ACCOUNT - TOWERS & FIXTURES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	74,166	-	0.00	22,876	30.84	(22,876)	(30.84)				(119.93)
1998	64,024	-	0.00	22,369	34.94	(22,369)	(34.94)				(126.22)
1999	73,660	-	0.00	10,904	14.80	(10,904)	(14.80)				(132.14)
2000	-	-	0.00	21,515	0.00	(21,515)	0.00				(141.61)
2001	18,840	-	0.00	16,155	85.75	(16,155)	(85.75)			(40.67)	(139.25)
2002	-	-	0.00	-	0.00	-	0.00			(45.32)	(140.38)
2003	-	-	0.00	-	0.00	-	0.00			(52.51)	(140.38)
2004	27,604	-	0.00	109,131	395.34	(109,131)	(395.34)			(316.08)	(140.38)
2005	544,750	-	0.00	15,171	2.78	(15,171)	(2.78)	34,024,284	1.60%	(23.76)	(132.26)
2006	-	-	0.00	-	0.00	-	0.00	40,245,442	0.00%	(21.72)	(351.40)
2007	17,203	-	0.00	24,346	141.52	(24,346)	(141.52)	42,693,624	0.04%	(25.21)	(351.40)
2008	47,688	-	0.00	155,138	325.32	(155,138)	(325.32)	46,011,686	0.10%	(47.67)	(363.25)
2009	249,646	-	0.00	768,892	307.99	(768,892)	(307.99)	45,867,370	0.54%	(112.13)	(370.28)
2010	3,645	-	0.00	136,428	3,742.88	(136,428)	(3,742.88)	46,983,550	0.01%	(340.94)	(2,495.04)
2011	3,674	-	0.00	46,183	1,257.03	(46,183)	(1,257.03)	48,087,326	0.01%	(351.40)	(1,257.03)
TOTAL (15)	1,124,900	-	0.00	1,349,107	119.93	(1,349,107)	(119.93)	48,087,326	2.34%		

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SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-354.2**
ACCOUNT - TOWERS & FIXTURES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	-	0.00	-	0.00				NA
1992	-	-	0.00	-	0.00	-	0.00				NA
1993	-	-	0.00	-	0.00	-	0.00				NA
1994	-	-	0.00	-	0.00	-	0.00				NA
1995	-	-	0.00	-	0.00	-	0.00			NA	NA
1996	-	-	0.00	-	0.00	-	0.00			NA	NA
1997	-	-	0.00	-	0.00	-	0.00			NA	NA
1998	-	-	0.00	-	0.00	-	0.00			NA	NA
1999	-	-	0.00	-	0.00	-	0.00			NA	NA
2000	-	-	0.00	-	0.00	-	0.00			NA	NA
2001	-	-	0.00	-	0.00	-	0.00			NA	NA
2002	-	-	0.00	-	0.00	-	0.00			NA	NA
2003	-	-	0.00	-	0.00	-	0.00			NA	NA
2004	-	-	0.00	-	0.00	-	0.00			NA	NA
2005	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%	NA	NA
Totals	-	-	**0.00**	-	**0.00**	-	**0.00**	61,988,482	0.00%		

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SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-354.2**
ACCOUNT - TOWERS & FIXTURES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	-	0.00	-	0.00				NA
1998	-	-	0.00	-	0.00	-	0.00				NA
1999	-	-	0.00	-	0.00	-	0.00				NA
2000	-	-	0.00	-	0.00	-	0.00				NA
2001	-	-	0.00	-	0.00	-	0.00			NA	NA
2002	-	-	0.00	-	0.00	-	0.00			NA	NA
2003	-	-	0.00	-	0.00	-	0.00			NA	NA
2004	-	-	0.00	-	0.00	-	0.00			NA	NA
2005	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%	NA	NA
2006	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%	NA	NA
2007	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%	NA	NA
2008	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%	NA	NA
2009	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%	NA	NA
2010	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%	NA	NA
TOTAL (15)	-	-	0.00	-	0.00	-	0.00	61,988,482	0.00%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-354.60

ACCOUNT - **Sunrise** TOWERS & FIXTURES - SRPL PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAI FNS % (K)	SHRINKING BAND INS % @2011 (L)
2010	-	-	0.00	-	0.00	-	0.00	70,350	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	111,180	0.00%	NA	NA
TOTAL (2)	-	-	0.00	-	0.00	-	0.00	111,180	0.00%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

E-355 Totals

ACCOUNT - POLES & FIXTURES PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	123,451	32,194	26.08	86,390	69.98	(54,196)	(43.90)				(77.58)
1992	80,254	3,835	4.78	328,318	409.10	(324,483)	(404.32)				(77.97)
1993	185,734	22,031	11.86	224,499	120.87	(202,468)	(109.01)				(75.51)
1994	244,670	5,095	2.08	164,887	67.39	(159,792)	(65.31)				(74.91)
1995	535,840	12,227	2.28	83,240	15.53	(71,013)	(13.25)			(69.40)	(75.14)
1996	140,763	858	0.61	181,243	128.76	(180,385)	(128.15)			(79.02)	(78.57)
1997	107,181	-	0.00	141,223	131.76	(141,223)	(131.76)			(62.17)	(77.84)
1998	265,935	-	0.00	237,391	89.27	(237,391)	(89.27)			(61.02)	(77.22)
1999	1,668,298	-	0.00	581,270	34.84	(581,270)	(34.84)			(44.56)	(76.87)
2000	838,408	-	0.00	744,771	88.83	(744,771)	(88.83)			(62.41)	(86.23)
2001	976,466	-	0.00	503,889	51.60	(503,889)	(51.60)			(57.27)	(85.90)
2002	1,237,300	557	0.05	884,642	71.50	(884,085)	(71.45)			(59.19)	(91.80)
2003	1,071,234	-	0.00	1,639,556	153.05	(1,639,556)	(153.05)			(75.17)	(97.46)
2004	2,081,012	-	0.00	1,508,639	72.50	(1,508,639)	(72.50)			(85.12)	(79.80)
2005	1,290,841	-	0.00	1,182,133	91.58	(1,182,133)	(91.58)	103,195,454	1.25%	(85.90)	(91.58)
Totals	10,847,386	76,797	0.71	8,492,091	78.29	(8,415,294)	(77.58)	103,195,454	10.51%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

E-355 Totals

ACCOUNT - POLES & FIXTURES PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	107,181	-	0.00	141,223	131.76	(141,223)	(131.76)				(106.31)
1998	265,935	-	0.00	237,391	89.27	(237,391)	(89.27)				(106.19)
1999	1,668,298	-	0.00	581,270	34.84	(581,270)	(34.84)				(106.39)
2000	838,408	-	0.00	744,771	88.83	(744,771)	(88.83)				(112.13)
2001	976,466	-	0.00	503,889	51.60	(503,889)	(51.60)			(57.27)	(113.10)
2002	1,237,300	557	0.05	884,642	71.50	(884,085)	(71.45)			(59.19)	(116.27)
2003	1,071,234	-	0.00	1,639,556	153.05	(1,639,556)	(153.05)			(75.17)	(119.39)
2004	2,081,012	-	0.00	1,508,639	72.50	(1,508,639)	(72.50)			(85.12)	(117.23)
2005	1,290,841	-	0.00	1,182,133	91.58	(1,182,133)	(91.58)	103,195,454	1.25%	(85.90)	(123.60)
2006	1,059,406	39,314	3.71	403,451	38.08	(364,137)	(34.37)	109,482,769	0.97%	(82.77)	(126.71)
2007	3,055,924	-	0.00	1,568,166	51.32	(1,568,166)	(51.32)	126,723,541	2.41%	(73.18)	(134.69)
2008	2,918,403	-	0.00	2,735,759	93.74	(2,735,759)	(93.74)	135,091,835	2.16%	(70.72)	(162.39)
2009	2,472,487	1,066	0.04	5,592,418	226.19	(5,591,352)	(226.14)	171,014,838	1.45%	(105.97)	(194.29)
2010	2,067,527	1,062	0.05	1,695,944	82.03	(1,694,882)	(81.98)	197,528,817	1.05%	(103.29)	(173.60)
2011	1,739,701	-	0.00	4,914,553	282.49	(4,914,553)	(282.49)	232,493,071	0.75%	(134.69)	(282.49)
TOTAL (15)	22,850,123	41,999	0.18	24,333,805	106.49	(24,291,806)	(106.31)	232,493,071	9.83%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-355.1
ACCOUNT - POLES & FIXTURES   PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	123,451	32,194	26.08	86,390	69.98	(54,196)	(43.90)				(77.58)
1992	80,254	3,835	4.78	328,318	409.10	(324,483)	(404.32)				(77.97)
1993	185,734	22,031	11.86	224,499	120.87	(202,468)	(109.01)				(75.51)
1994	244,670	5,095	2.08	164,887	67.39	(159,792)	(65.31)				(74.91)
1995	535,840	12,227	2.28	83,240	15.53	(71,013)	(13.25)			(69.40)	(75.14)
1996	140,763	858	0.61	181,243	128.76	(180,385)	(128.15)			(79.02)	(78.57)
1997	107,181	-	0.00	141,223	131.76	(141,223)	(131.76)			(62.17)	(77.84)
1998	265,935	-	0.00	237,391	89.27	(237,391)	(89.27)			(61.02)	(77.22)
1999	1,668,298	-	0.00	581,270	34.84	(581,270)	(34.84)			(44.56)	(76.87)
2000	838,408	-	0.00	744,771	88.83	(744,771)	(88.83)			(62.41)	(86.23)
2001	976,466	-	0.00	503,889	51.60	(503,889)	(51.60)			(57.27)	(85.90)
2002	1,237,300	557	0.05	884,642	71.50	(884,085)	(71.45)			(59.19)	(91.80)
2003	1,071,234	-	0.00	1,639,556	153.05	(1,639,556)	(153.05)			(75.17)	(97.46)
2004	2,081,012	-	0.00	1,508,639	72.50	(1,508,639)	(72.50)			(85.12)	(79.80)
2005	1,290,841	-	0.00	1,182,133	91.58	(1,182,133)	(91.58)	95,277,179	1.35%	(85.90)	(91.58)
Totals	10,847,386	76,797	0.71	8,492,091	78.29	(8,415,294)	(77.58)	95,277,179	11.39%		

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SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-355.1
ACCOUNT - POLES & FIXTURES   PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	107,181	-	0.00	141,223	131.76	(141,223)	(131.76)				(106.31)
1998	265,935	-	0.00	237,391	89.27	(237,391)	(89.27)				(106.19)
1999	1,668,298	-	0.00	581,270	34.84	(581,270)	(34.84)				(106.39)
2000	838,408	-	0.00	744,771	88.83	(744,771)	(88.83)				(112.13)
2001	976,466	-	0.00	503,889	51.60	(503,889)	(51.60)			(57.27)	(113.10)
2002	1,237,300	557	0.05	884,642	71.50	(884,085)	(71.45)			(59.19)	(116.27)
2003	1,071,234	-	0.00	1,639,556	153.05	(1,639,556)	(153.05)			(75.17)	(119.39)
2004	2,081,012	-	0.00	1,508,639	72.50	(1,508,639)	(72.50)			(85.12)	(117.23)
2005	1,290,841	-	0.00	1,182,133	91.58	(1,182,133)	(91.58)	95,277,179	1.35%	(85.90)	(123.60)
2006	1,059,406	39,314	3.71	403,451	38.08	(364,137)	(34.37)	101,376,209	1.05%	(82.77)	(126.71)
2007	3,055,924	-	0.00	1,568,166	51.32	(1,568,166)	(51.32)	118,616,981	2.58%	(73.18)	(134.69)
2008	2,918,403	-	0.00	2,735,759	93.74	(2,735,759)	(93.74)	126,985,275	2.30%	(70.72)	(162.39)
2009	2,472,487	1,066	0.04	5,592,418	226.19	(5,591,352)	(226.14)	162,908,278	1.52%	(105.97)	(194.29)
2010	2,067,527	1,062	0.05	1,695,944	82.03	(1,694,882)	(81.98)	189,420,363	1.09%	(103.29)	(173.60)
2011	1,739,701	-	0.00	4,914,553	282.49	(4,914,553)	(282.49)	223,792,702	0.78%	(134.69)	(282.49)
TOTAL (15)	22,850,123	41,999	0.18	24,333,805	106.49	(24,291,806)	(106.31)	223,792,702	10.21%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-355.2**
ACCOUNT - POLES & FIXTURES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	-	0.00	-	0.00				NA
1992	-	-	0.00	-	0.00	-	0.00				NA
1993	-	-	0.00	-	0.00	-	0.00				NA
1994	-	-	0.00	-	0.00	-	0.00				NA
1995	-	-	0.00	-	0.00	-	0.00			NA	NA
1996	-	-	0.00	-	0.00	-	0.00			NA	NA
1997	-	-	0.00	-	0.00	-	0.00			NA	NA
1998	-	-	0.00	-	0.00	-	0.00			NA	NA
1999	-	-	0.00	-	0.00	-	0.00			NA	NA
2000	-	-	0.00	-	0.00	-	0.00			NA	NA
2001	-	-	0.00	-	0.00	-	0.00			NA	NA
2002	-	-	0.00	-	0.00	-	0.00			NA	NA
2003	-	-	0.00	-	0.00	-	0.00			NA	NA
2004	-	-	0.00	-	0.00	-	0.00			NA	NA
2005	-	-	0.00	-	0.00	-	0.00	7,918,275	0.00%	NA	NA
Totals	-	-	**0.00**	-	**0.00**	-	**0.00**	7,918,275	0.00%		

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SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-355.2**
ACCOUNT - POLES & FIXTURES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	-	0.00	-	0.00				NA
1998	-	-	0.00	-	0.00	-	0.00				NA
1999	-	-	0.00	-	0.00	-	0.00				NA
2000	-	-	0.00	-	0.00	-	0.00				NA
2001	-	-	0.00	-	0.00	-	0.00			NA	NA
2002	-	-	0.00	-	0.00	-	0.00			NA	NA
2003	-	-	0.00	-	0.00	-	0.00			NA	NA
2004	-	-	0.00	-	0.00	-	0.00			NA	NA
2005	-	-	0.00	-	0.00	-	0.00	7,918,275	0.00%	NA	NA
2006	-	-	0.00	-	0.00	-	0.00	8,106,560	0.00%	NA	NA
2007	-	-	0.00	-	0.00	-	0.00	8,106,560	0.00%	NA	NA
2008	-	-	0.00	-	0.00	-	0.00	8,106,560	0.00%	NA	NA
2009	-	-	0.00	-	0.00	-	0.00	8,106,560	0.00%	NA	NA
2010	-	-	0.00	-	0.00	-	0.00	8,106,560	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	8,106,560	0.00%	NA	NA
TOTAL (15)	-	-	0.00	-	0.00	-	0.00	8,106,560	0.00%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-355.60

ACCOUNT - Sunrise POLES & FIXTURES - SRPL PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAI FNS % (K)	SHRINKING BAND INS % @2011 (L)
2010	-	-	0.00	-	0.00	-	0.00	1,894	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	593,809	0.00%	NA	NA
TOTAL (2)	-	-	0.00	-	0.00	-	0.00	593,809	0.00%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

E-356 Totals

ACCOUNT - OVERHEAD CONDUCTORS & DEVICES PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	154,699	47,289	30.57	143,037	92.46	(95,748)	(61.89)				(89.07)
1992	94,405	1,264	1.34	446,070	472.51	(444,806)	(471.17)				(89.50)
1993	430,142	34,563	8.04	303,392	70.53	(268,829)	(62.50)				(85.79)
1994	532,104	7,343	1.38	148,359	27.88	(141,016)	(26.50)				(86.87)
1995	1,483,725	-	0.00	199,246	13.43	(199,246)	(13.43)			(42.66)	(90.54)
1996	200,223	6	0.00	258,821	129.27	(258,815)	(129.26)			(47.90)	(106.29)
1997	84,062	-	0.00	161,438	192.05	(161,438)	(192.05)			(37.70)	(105.64)
1998	200,822	-	0.00	335,680	167.15	(335,680)	(167.15)			(43.83)	(104.60)
1999	966,161	-	0.00	787,321	81.49	(787,321)	(81.49)			(59.37)	(102.75)
2000	308,809	-	0.00	1,049,111	339.73	(1,049,111)	(339.73)			(147.29)	(106.28)
2001	1,340,342	-	0.00	1,877,240	140.06	(1,877,240)	(140.06)			(145.19)	(93.18)
2002	1,154,357	557	0.05	648,295	56.16	(647,737)	(56.11)			(118.30)	(78.09)
2003	496,330	-	0.00	802,270	161.64	(802,270)	(161.64)			(121.04)	(86.52)
2004	1,638,424	-	0.00	966,799	59.01	(966,799)	(59.01)			(108.20)	(71.68)
2005	873,724	-	0.00	833,998	95.45	(833,998)	(95.45)	177,548,406	0.49%	(93.18)	(95.45)
Totals	9,958,329	91,022	0.91	8,961,077	89.99	(8,870,055)	(89.07)	177,548,406	5.61%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

E-356 Totals

ACCOUNT - OVERHEAD CONDUCTORS & DEVICES PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	84,062	-	0.00	161,438	192.05	(161,438)	(192.05)				(118.71)
1998	200,822	-	0.00	335,680	167.15	(335,680)	(167.15)				(118.20)
1999	966,161	-	0.00	787,321	81.49	(787,321)	(81.49)				(117.39)
2000	308,809	-	0.00	1,049,111	339.73	(1,049,111)	(339.73)				(120.52)
2001	1,340,342	-	0.00	1,877,240	140.06	(1,877,240)	(140.06)			(145.19)	(114.23)
2002	1,154,357	557	0.05	648,295	56.16	(647,737)	(56.11)			(118.30)	(110.56)
2003	496,330	-	0.00	802,270	161.64	(802,270)	(161.64)			(121.04)	(118.16)
2004	1,638,424	-	0.00	966,799	59.01	(966,799)	(59.01)			(108.20)	(115.38)
2005	873,724	-	0.00	833,998	95.45	(833,998)	(95.45)	177,548,406	0.49%	(93.18)	(130.45)
2006	1,065,253	321,097	30.14	164,721	15.46	156,376	14.68	203,210,160	0.52%	(59.19)	(136.26)
2007	845,162	-	0.00	758,275	89.72	(758,275)	(89.72)	215,753,429	0.39%	(65.16)	(174.62)
2008	904,122	-	0.00	631,669	69.87	(631,669)	(69.87)	230,467,910	0.39%	(56.97)	(196.07)
2009	667,649	-	0.00	1,338,898	200.54	(1,338,898)	(200.54)	255,676,258	0.26%	(78.20)	(242.78)
2010	935,894	-	0.00	1,537,856	164.32	(1,537,856)	(164.32)	270,040,865	0.35%	(93.03)	(258.67)
2011	838,850	-	0.00	3,052,945	363.94	(3,052,945)	(363.94)	287,571,912	0.29%	(174.62)	(363.94)
TOTAL (15)	12,319,960	321,654	2.61	14,946,516	121.32	(14,624,862)	(118.71)	287,571,912	4.28%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-356.1**
ACCOUNT - OVERHEAD CONDUCTORS & DEVICES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	154,699	47,289	30.57	143,037	92.46	(95,748)	(61.89)				(89.08)
1992	94,405	1,264	1.34	446,070	472.51	(444,806)	(471.17)				(89.51)
1993	430,142	34,563	8.04	303,392	70.53	(268,829)	(62.50)				(85.79)
1994	532,104	7,343	1.38	148,359	27.88	(141,016)	(26.50)				(86.87)
1995	1,483,725	-	0.00	199,246	13.43	(199,246)	(13.43)			(42.66)	(90.55)
1996	200,223	6	0.00	258,821	129.27	(258,815)	(129.26)			(47.90)	(106.30)
1997	84,062	-	0.00	161,438	192.05	(161,438)	(192.05)			(37.70)	(105.65)
1998	200,822	-	0.00	335,680	167.15	(335,680)	(167.15)			(43.83)	(104.61)
1999	965,653	-	0.00	787,321	81.53	(787,321)	(81.53)			(59.38)	(102.76)
2000	308,809	-	0.00	1,049,111	339.73	(1,049,111)	(339.73)			(147.33)	(106.28)
2001	1,340,342	-	0.00	1,877,240	140.06	(1,877,240)	(140.06)			(145.22)	(93.18)
2002	1,154,357	557	0.05	648,295	56.16	(647,737)	(56.11)			(118.32)	(78.09)
2003	496,330	-	0.00	802,270	161.64	(802,270)	(161.64)			(121.06)	(86.52)
2004	1,638,424	-	0.00	966,799	59.01	(966,799)	(59.01)			(108.20)	(71.68)
2005	873,724	-	0.00	833,998	95.45	(833,998)	(95.45)	135,394,778	0.65%	(93.18)	(95.45)
Totals	9,957,820	91,022	0.91	8,961,077	89.99	(8,870,055)	(89.08)	135,394,778	7.35%		

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SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-356.1**
ACCOUNT - OVERHEAD CONDUCTORS & DEVICES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	84,062	-	0.00	161,438	192.05	(161,438)	(192.05)				(118.71)
1998	200,822	-	0.00	335,680	167.15	(335,680)	(167.15)				(118.21)
1999	965,653	-	0.00	787,321	81.53	(787,321)	(81.53)				(117.39)
2000	308,809	-	0.00	1,049,111	339.73	(1,049,111)	(339.73)				(120.52)
2001	1,340,342	-	0.00	1,877,240	140.06	(1,877,240)	(140.06)			(145.22)	(114.23)
2002	1,154,357	557	0.05	648,295	56.16	(647,737)	(56.11)			(118.32)	(110.56)
2003	496,330	-	0.00	802,270	161.64	(802,270)	(161.64)			(121.06)	(118.16)
2004	1,638,424	-	0.00	966,799	59.01	(966,799)	(59.01)			(108.20)	(115.38)
2005	873,724	-	0.00	833,998	95.45	(833,998)	(95.45)	135,394,778	0.65%	(93.18)	(130.45)
2006	1,065,253	321,097	30.14	164,721	15.46	156,376	14.68	161,056,532	0.66%	(59.19)	(136.26)
2007	845,162	-	0.00	758,275	89.72	(758,275)	(89.72)	173,599,801	0.49%	(65.16)	(174.62)
2008	904,122	-	0.00	631,669	69.87	(631,669)	(69.87)	188,314,282	0.48%	(56.97)	(196.07)
2009	667,649	-	0.00	1,338,898	200.54	(1,338,898)	(200.54)	213,522,630	0.31%	(78.20)	(242.78)
2010	935,894	-	0.00	1,537,856	164.32	(1,537,856)	(164.32)	227,861,446	0.41%	(93.03)	(258.67)
2011	838,850	-	0.00	3,052,945	363.94	(3,052,945)	(363.94)	243,805,493	0.34%	(174.62)	(363.94)
TOTAL (15)	12,319,452	321,654	2.61	14,946,516	121.32	(14,624,862)	(118.71)	243,805,493	5.05%		

APPENDIX "B"

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-356.2**
ACCOUNT - OVERHEAD CONDUCTORS & DEVICES   PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	-	0.00	-	0.00				-
1992	-	-	0.00	-	0.00	-	0.00				-
1993	-	-	0.00	-	0.00	-	0.00				-
1994	-	-	0.00	-	0.00	-	0.00				-
1995	-	-	0.00	-	0.00	-	0.00			NA	-
1996	-	-	0.00	-	0.00	-	0.00			NA	-
1997	-	-	0.00	-	0.00	-	0.00			NA	-
1998	-	-	0.00	-	0.00	-	0.00			NA	-
1999	508	-	0.00	-	0.00	-	0.00			-	-
2000	-	-	0.00	-	0.00	-	0.00			-	NA
2001	-	-	0.00	-	0.00	-	0.00			-	NA
2002	-	-	0.00	-	0.00	-	0.00			-	NA
2003	-	-	0.00	-	0.00	-	0.00			-	NA
2004	-	-	0.00	-	0.00	-	0.00			NA	NA
2005	-	-	0.00	-	0.00	-	0.00	42,153,628	0.00%	NA	NA
Totals	508	-	0.00	-	0.00	-	0.00	42,153,628	0.00%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-356.2**
ACCOUNT - OVERHEAD CONDUCTORS & DEVICES   PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	-	0.00	-	0.00				-
1998	-	-	0.00	-	0.00	-	0.00				-
1999	508	-	0.00	-	0.00	-	0.00				-
2000	-	-	0.00	-	0.00	-	0.00				-
2001	-	-	0.00	-	0.00	-	0.00			-	-
2002	-	-	0.00	-	0.00	-	0.00			-	-
2003	-	-	0.00	-	0.00	-	0.00			-	-
2004	-	-	0.00	-	0.00	-	0.00			NA	-
2005	-	-	0.00	-	0.00	-	0.00	42,153,628	0.00%	NA	-
2006	-	-	0.00	-	0.00	-	0.00	42,153,628	0.00%	NA	-
2007	-	-	0.00	-	0.00	-	0.00	42,153,628	0.00%	NA	-
2008	-	-	0.00	-	0.00	-	0.00	42,153,628	0.00%	NA	-
2009	-	-	0.00	-	0.00	-	0.00	42,153,628	0.00%	NA	-
2010	-	-	0.00	-	0.00	-	0.00	42,153,628	0.00%	NA	-
2011	-	-	0.00	-	0.00	-	0.00	42,153,628	0.00%	NA	-
TOTAL (15)	508	-	0.00	-	0.00	-	0.00	42,153,628	0.00%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-356.60

ACCOUNT - Sunrise OVHD CND & DEV -SRPL PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAI FNS % (K)	SHRINKING BAND INS % @2011 (L)
2010	-	-	0.00	-	0.00	-	0.00	25,791	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	1,612,791	0.00%	NA	NA
TOTAL (2)	-	-	0.00	-	0.00	-	0.00	1,612,791	0.00%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY

E-357 Totals

ACCOUNT - UNDERGROUND CONDUIT PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	171	0.00	(171)	0.00				(43.98)
1992	-	-	0.00	2,275	0.00	(2,275)	0.00				(43.92)
1993	-	-	0.00	861	0.00	(861)	0.00				(43.13)
1994	4,568	-	0.00	353	7.73	(353)	(7.73)				(42.83)
1995	466	-	0.00	-	0.00	-	0.00			(72.71)	(43.39)
1996	118,884	23,394	19.68	546	0.46	22,848	19.22			15.62	(43.46)
1997	-	-	0.00	-	0.00	-	0.00			17.46	(89.17)
1998	12,055	-	0.00	-	0.00	-	0.00			16.54	(89.17)
1999	7,318	-	0.00	60,647	828.78	(60,647)	(828.78)			(27.25)	(96.29)
2000	1,790	-	0.00	29,085	1,624.84	(29,085)	(1,624.84)			(47.76)	(58.98)
2001	54,063	-	0.00	6,895	12.75	(6,895)	(12.75)			(128.45)	(39.23)
2002	6,512	-	0.00	3,436	52.77	(3,436)	(52.77)			(122.42)	(55.52)
2003	57,788	-	0.00	8,671	15.01	(8,671)	(15.01)			(85.30)	(55.74)
2004	1,855	-	0.00	13,637	735.18	(13,637)	(735.18)			(50.59)	(155.82)
2005	21,670	-	0.00	23,019	106.23	(23,019)	(106.23)	40,817,077	0.05%	(39.23)	(106.23)
Totals	286,969	23,394	8.15	149,597	52.13	(126,203)	(43.98)	40,817,077	0.70%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

E-357 Totals

ACCOUNT - UNDERGROUND CONDUIT PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	-	0.00	-	0.00				(89.19)
1998	12,055	-	0.00	-	0.00	-	0.00				(89.19)
1999	7,318	-	0.00	60,647	828.78	(60,647)	(828.78)				(96.29)
2000	1,790	-	0.00	29,085	1,624.84	(29,085)	(1,624.84)				(59.08)
2001	54,063	-	0.00	6,895	12.75	(6,895)	(12.75)			(128.45)	(39.37)
2002	6,512	-	0.00	3,436	52.77	(3,436)	(52.77)			(122.42)	(55.69)
2003	57,788	-	0.00	8,671	15.01	(8,671)	(15.01)			(85.30)	(55.93)
2004	1,855	-	0.00	13,637	735.18	(13,637)	(735.18)			(50.59)	(155.01)
2005	21,670	-	0.00	23,019	106.23	(23,019)	(106.23)	40,817,077	0.05%	(39.23)	(106.12)
2006	-	-	0.00	-	0.00	-	0.00	44,769,469	0.00%	(55.52)	(99.12)
2007	-	-	0.00	62	0.00	(62)	0.00	105,508,143	0.00%	(55.82)	(99.12)
2008	341	-	0.00	178	52.20	(178)	(52.20)	125,052,734	0.00%	(154.60)	(80.94)
2009	-	-	0.00	98	0.00	(98)	0.00	129,368,482	0.00%	(106.12)	NA
2010	-	-	0.00	-	0.00	-	0.00	133,036,220	0.00%	(99.12)	NA
2011	-	-	0.00	-	0.00	-	0.00	136,727,462	0.00%	(99.12)	NA
TOTAL (15)	163,392	-	0.00	145,729	89.19	(145,729)	(89.19)	136,727,462	0.12%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-357**
ACCOUNT - UNDERGROUND CONDUIT PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	171	0.00	(171)	0.00				(43.98)
1992	-	-	0.00	2,275	0.00	(2,275)	0.00				(43.92)
1993	-	-	0.00	861	0.00	(861)	0.00				(43.13)
1994	4,568	-	0.00	353	7.73	(353)	(7.73)				(42.83)
1995	466	-	0.00	-	0.00	-	0.00			(72.71)	(43.39)
1996	118,884	23,394	19.68	546	0.46	22,848	19.22			15.62	(43.46)
1997	-	-	0.00	-	0.00	-	0.00			17.46	(89.17)
1998	12,055	-	0.00	-	0.00	-	0.00			16.54	(89.17)
1999	7,318	-	0.00	60,647	828.78	(60,647)	(828.78)			(27.25)	(96.29)
2000	1,790	-	0.00	29,085	1,624.84	(29,085)	(1,624.84)			(47.76)	(58.98)
2001	54,063	-	0.00	6,895	12.75	(6,895)	(12.75)			(128.45)	(39.23)
2002	6,512	-	0.00	3,436	52.77	(3,436)	(52.77)			(122.42)	(55.52)
2003	57,788	-	0.00	8,671	15.01	(8,671)	(15.01)			(85.30)	(55.74)
2004	1,855	-	0.00	13,637	735.18	(13,637)	(735.18)			(50.59)	(155.82)
2005	21,670	-	0.00	23,019	106.23	(23,019)	(106.23)	40,817,077	0.05%	(39.23)	(106.23)
Totals	**286,969**	**23,394**	**8.15**	**149,597**	**52.13**	**(126,203)**	**(43.98)**	**40,817,077**	**0.70%**		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-357**
ACCOUNT - UNDERGROUND CONDUIT PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	-	0.00	-	0.00				(89.19)
1998	12,055	-	0.00	-	0.00	-	0.00				(89.19)
1999	7,318	-	0.00	60,647	828.78	(60,647)	(828.78)				(96.29)
2000	1,790	-	0.00	29,085	1,624.84	(29,085)	(1,624.84)				(59.08)
2001	54,063	-	0.00	6,895	12.75	(6,895)	(12.75)			(128.45)	(39.37)
2002	6,512	-	0.00	3,436	52.77	(3,436)	(52.77)			(122.42)	(55.69)
2003	57,788	-	0.00	8,671	15.01	(8,671)	(15.01)			(85.30)	(55.93)
2004	1,855	-	0.00	13,637	735.18	(13,637)	(735.18)			(50.59)	(155.01)
2005	21,670	-	0.00	23,019	106.23	(23,019)	(106.23)	40,817,077	0.05%	(39.23)	(106.12)
2006	-	-	0.00	-	0.00	-	0.00	44,769,469	0.00%	(55.52)	(99.12)
2007	-	-	0.00	62	0.00	(62)	0.00	105,508,143	0.00%	(55.82)	(99.12)
2008	341	-	0.00	178	52.20	(178)	(52.20)	125,052,734	0.00%	(154.60)	(80.94)
2009	-	-	0.00	98	0.00	(98)	0.00	129,368,482	0.00%	(106.12)	NA
2010	-	-	0.00	-	0.00	-	0.00	133,002,065	0.00%	(99.12)	NA
2011	-	-	0.00	-	0.00	-	0.00	136,576,747	0.00%	(99.12)	NA
TOTAL (15)	163,392	-	0.00	145,729	89.19	(145,729)	(89.19)	136,576,747	0.12%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-357.60

ACCOUNT - Sunrise TRANS UG COND - SRPL PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAI FNS % (K)	SHRINKING BAND INS % @2011 (L)
2010	-	-	0.00	-	0.00	-	0.00	34,155	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	150,715	0.00%	NA	NA
TOTAL (2)	-	-	0.00	-	0.00	-	0.00	150,715	0.00%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY

E-358 Totals

ACCOUNT - UNDERGROUND CONDUCTORS & DEVICES PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	12,893	11,281	87.50	6,614	51.30	4,667	36.20				(8.47)
1992	76,184	14,965	19.64	4,047	5.31	10,918	14.33				(8.62)
1993	43,156	7,456	17.28	1,975	4.58	5,481	12.70				(9.08)
1994	73,275	-	0.00	12,111	16.53	(12,111)	(16.53)				(9.33)
1995	30,808	31,611	102.61	6,444	20.92	25,167	81.69			14.44	(9.18)
1996	152,838	5,184	3.39	(72)	(0.05)	5,256	3.44			9.23	(9.95)
1997	88,429	-	0.00	182	0.21	(182)	(0.21)			6.08	(10.54)
1998	9,540	-	0.00	1,000	10.48	(1,000)	(10.48)			4.83	(10.80)
1999	1,457,663	-	0.00	38,376	2.63	(38,376)	(2.63)			(0.53)	(10.81)
2000	243,288	-	0.00	70,478	28.97	(70,478)	(28.97)			(5.37)	(16.94)
2001	1,156,103	-	0.00	62,149	5.38	(62,149)	(5.38)			(5.83)	(15.22)
2002	15,495	1,181	7.62	5,850	37.75	(4,668)	(30.13)			(6.13)	(36.24)
2003	212,609	-	0.00	16,229	7.63	(16,229)	(7.63)			(6.22)	(36.42)
2004	32,577	-	0.00	44,782	137.46	(44,782)	(137.46)			(11.95)	(55.94)
2005	280,860	-	0.00	130,564	46.49	(130,564)	(46.49)	28,143,063	1.00%	(15.22)	(46.49)
Totals	3,885,717	71,678	1.84	400,728	10.31	(329,050)	(8.47)	28,143,063	13.81%		

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SAN DIEGO GAS AND ELECTRIC COMPANY

E-358 Totals

ACCOUNT - UNDERGROUND CONDUCTORS & DEVICES PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	88,429	-	0.00	182	0.21	(182)	(0.21)				(10.97)
1998	9,540	-	0.00	1,000	10.48	(1,000)	(10.48)				(11.25)
1999	1,457,663	-	0.00	38,376	2.63	(38,376)	(2.63)				(11.25)
2000	243,288	-	0.00	70,478	28.97	(70,478)	(28.97)				(17.60)
2001	1,156,103	-	0.00	62,149	5.38	(62,149)	(5.38)			(5.83)	(16.00)
2002	15,495	1,181	7.62	5,850	37.75	(4,668)	(30.13)			(6.13)	(37.22)
2003	212,609	-	0.00	16,229	7.63	(16,229)	(7.63)			(6.22)	(37.42)
2004	32,577	-	0.00	44,782	137.46	(44,782)	(137.46)			(11.95)	(55.48)
2005	280,860	-	0.00	130,564	46.49	(130,564)	(46.49)	28,143,063	1.00%	(15.22)	(47.08)
2006	5,524	-	0.00	332	6.01	(332)	(6.01)	32,764,509	0.02%	(35.93)	(51.57)
2007	-	-	0.00	447	0.00	(447)	0.00	91,483,794	0.00%	(36.19)	(59.51)
2008	31,682	-	0.00	10,794	34.07	(10,794)	(34.07)	101,955,594	0.03%	(53.31)	(58.10)
2009	-	-	0.00	7,613	0.00	(7,613)	0.00	110,514,092	0.00%	(47.08)	NA
2010	-	-	0.00	-	0.00	-	0.00	116,916,117	0.00%	(51.57)	NA
2011	-	-	0.00	-	0.00	-	0.00	125,792,671	0.00%	(59.51)	NA
TOTAL (15)	3,533,769	1,181	0.03	388,795	11.00	(387,614)	(10.97)	125,792,671	2.81%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-358**
ACCOUNT - UNDERGROUND CONDUCTORS & DEVICES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	12,893	11,281	87.50	6,614	51.30	4,667	36.20				(8.47)
1992	76,184	14,965	19.64	4,047	5.31	10,918	14.33				(8.62)
1993	43,156	7,456	17.28	1,975	4.58	5,481	12.70				(9.08)
1994	73,275	-	0.00	12,111	16.53	(12,111)	(16.53)				(9.33)
1995	30,808	31,611	102.61	6,444	20.92	25,167	81.69			14.44	(9.18)
1996	152,838	5,184	3.39	(72)	(0.05)	5,256	3.44			9.23	(9.95)
1997	88,429	-	0.00	182	0.21	(182)	(0.21)			6.08	(10.54)
1998	9,540	-	0.00	1,000	10.48	(1,000)	(10.48)			4.83	(10.80)
1999	1,457,663	-	0.00	38,376	2.63	(38,376)	(2.63)			(0.53)	(10.81)
2000	243,288	-	0.00	70,478	28.97	(70,478)	(28.97)			(5.37)	(16.94)
2001	1,156,103	-	0.00	62,149	5.38	(62,149)	(5.38)			(5.83)	(15.22)
2002	15,495	1,181	7.62	5,850	37.75	(4,668)	(30.13)			(6.13)	(36.24)
2003	212,609	-	0.00	16,229	7.63	(16,229)	(7.63)			(6.22)	(36.42)
2004	32,577	-	0.00	44,782	137.46	(44,782)	(137.46)			(11.95)	(55.94)
2005	280,860	-	0.00	130,564	46.49	(130,564)	(46.49)	28,143,063	1.00%	(15.22)	(46.49)
Totals	3,885,717	71,678	1.84	400,728	10.31	(329,050)	(8.47)	28,143,063	13.81%		

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SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-358**
ACCOUNT - UNDERGROUND CONDUCTORS & DEVICES PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	88,429	-	0.00	182	0.21	(182)	(0.21)				(10.97)
1998	9,540	-	0.00	1,000	10.48	(1,000)	(10.48)				(11.25)
1999	1,457,663	-	0.00	38,376	2.63	(38,376)	(2.63)				(11.25)
2000	243,288	-	0.00	70,478	28.97	(70,478)	(28.97)				(17.60)
2001	1,156,103	-	0.00	62,149	5.38	(62,149)	(5.38)			(5.83)	(16.00)
2002	15,495	1,181	7.62	5,850	37.75	(4,668)	(30.13)			(6.13)	(37.22)
2003	212,609	-	0.00	16,229	7.63	(16,229)	(7.63)			(6.22)	(37.42)
2004	32,577	-	0.00	44,782	137.46	(44,782)	(137.46)			(11.95)	(55.48)
2005	280,860	-	0.00	130,564	46.49	(130,564)	(46.49)	28,143,063	1.00%	(15.22)	(47.08)
2006	5,524	-	0.00	332	6.01	(332)	(6.01)	32,764,509	0.02%	(35.93)	(51.57)
2007	-	-	0.00	447	0.00	(447)	0.00	91,483,794	0.00%	(36.19)	(59.51)
2008	31,682	-	0.00	10,794	34.07	(10,794)	(34.07)	101,955,594	0.03%	(53.31)	(58.10)
2009	-	-	0.00	7,613	0.00	(7,613)	0.00	110,514,092	0.00%	(47.08)	NA
2010	-	-	0.00	-	0.00	-	0.00	116,880,243	0.00%	(51.57)	NA
2011	-	-	0.00	-	0.00	-	0.00	125,485,230	0.00%	(59.51)	NA
TOTAL (15)	3,533,769	1,181	0.03	388,795	11.00	(387,614)	(10.97)	125,485,230	2.82%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-358.60

ACCOUNT - **Sunrise** TRANS UG COND & DEV - SRPL PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAI FNS % (K)	SHRINKING BAND INS % @2011 (L)
2010	-	-	0.00	-	0.00	-	0.00	35,874	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	307,441	0.00%	NA	NA
TOTAL (2)	-	-	0.00	-	0.00	-	0.00	307,441	0.00%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY

E-359 Totals

ACCOUNT - ROADS & TRAILS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	-	0.00	-	0.00				(302.89)
1992	-	-	0.00	6,522	0.00	(6,522)	0.00				(302.89)
1993	-	-	0.00	350	0.00	(350)	0.00				(251.05)
1994	-	-	0.00	7,148	0.00	(7,148)	0.00				(248.27)
1995	-	-	0.00	597	0.00	(597)	0.00			NA	(191.45)
1996	3,770	-	0.00	92	2.44	(92)	(2.44)			(390.16)	(186.71)
1997	-	-	0.00	338	0.00	(338)	0.00			(226.13)	(265.55)
1998	-	-	0.00	974	0.00	(974)	0.00			(242.68)	(261.71)
1999	-	-	0.00	7,499	0.00	(7,499)	0.00			(251.99)	(250.66)
2000	-	-	0.00	7,464	0.00	(7,464)	0.00			(434.13)	(165.55)
2001	-	-	0.00	4,319	0.00	(4,319)	0.00			NA	(80.84)
2002	-	-	0.00	-	0.00	-	0.00			NA	(31.82)
2003	-	-	0.00	-	0.00	-	0.00			NA	(31.82)
2004	-	-	0.00	2,804	0.00	(2,804)	0.00			NA	(31.82)
2005	8,811	-	0.00	-	0.00	-	0.00	14,498,026	0.06%	(80.84)	-
Totals	12,581	-	0.00	38,106	302.89	(38,106)	(302.89)	14,498,026	0.09%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

E-359 Totals

ACCOUNT - ROADS & TRAILS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	338	0.00	(338)	0.00				(2,928.44)
1998	-	-	0.00	974	0.00	(974)	0.00				(2,924.60)
1999	-	-	0.00	7,499	0.00	(7,499)	0.00				(2,913.54)
2000	-	-	0.00	7,464	0.00	(7,464)	0.00				(2,828.44)
2001	-	-	0.00	4,319	0.00	(4,319)	0.00			NA	(2,743.73)
2002	-	-	0.00	-	0.00	-	0.00			NA	(2,694.71)
2003	-	-	0.00	-	0.00	-	0.00			NA	(2,694.71)
2004	-	-	0.00	2,804	0.00	(2,804)	0.00			NA	(2,694.71)
2005	8,811	-	0.00	-	0.00	-	0.00	14,498,026	0.06%	(80.84)	(2,662.89)
2006	-	-	0.00	-	0.00	-	0.00	18,541,761	0.00%	(31.82)	NA
2007	-	-	0.00	110,257	0.00	(110,257)	0.00	21,628,728	0.00%	(1,283.18)	NA
2008	-	-	0.00	124,370	0.00	(124,370)	0.00	22,647,414	0.00%	(2,694.71)	NA
2009	-	-	0.00	-	0.00	-	0.00	25,627,569	0.00%	(2,662.89)	NA
2010	-	-	0.00	-	0.00	-	0.00	27,786,988	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	34,042,577	0.00%	NA	NA
TOTAL (15)	8,811	-	0.00	258,024	2,928.44	(258,024)	(2,928.44)	34,042,577	0.03%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-359.1**
ACCOUNT - ROADS & TRAILS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	-	0.00	-	0.00				(302.89)
1992	-	-	0.00	6,522	0.00	(6,522)	0.00				(302.89)
1993	-	-	0.00	350	0.00	(350)	0.00				(251.05)
1994	-	-	0.00	7,148	0.00	(7,148)	0.00				(248.27)
1995	-	-	0.00	597	0.00	(597)	0.00			NA	(191.45)
1996	3,770	-	0.00	92	2.44	(92)	(2.44)			(390.16)	(186.71)
1997	-	-	0.00	338	0.00	(338)	0.00			(226.13)	(265.55)
1998	-	-	0.00	974	0.00	(974)	0.00			(242.68)	(261.71)
1999	-	-	0.00	7,499	0.00	(7,499)	0.00			(251.99)	(250.66)
2000	-	-	0.00	7,464	0.00	(7,464)	0.00			(434.13)	(165.55)
2001	-	-	0.00	4,319	0.00	(4,319)	0.00			NA	(80.84)
2002	-	-	0.00	-	0.00	-	0.00			NA	(31.82)
2003	-	-	0.00	-	0.00	-	0.00			NA	(31.82)
2004	-	-	0.00	2,804	0.00	(2,804)	0.00			NA	(31.82)
2005	8,811	-	0.00	-	0.00	-	0.00	10,071,163	0.09%	(80.84)	-
Totals	12,581	-	0.00	38,106	302.89	(38,106)	(302.89)	10,071,163	0.12%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-359.1**
ACCOUNT - ROADS & TRAILS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	338	0.00	(338)	0.00				(2,928.44)
1998	-	-	0.00	974	0.00	(974)	0.00				(2,924.60)
1999	-	-	0.00	7,499	0.00	(7,499)	0.00				(2,913.54)
2000	-	-	0.00	7,464	0.00	(7,464)	0.00				(2,828.44)
2001	-	-	0.00	4,319	0.00	(4,319)	0.00			NA	(2,743.73)
2002	-	-	0.00	-	0.00	-	0.00			NA	(2,694.71)
2003	-	-	0.00	-	0.00	-	0.00			NA	(2,694.71)
2004	-	-	0.00	2,804	0.00	(2,804)	0.00			NA	(2,694.71)
2005	8,811	-	0.00	-	0.00	-	0.00	10,071,163	0.09%	(80.84)	(2,662.89)
2006	-	-	0.00	-	0.00	-	0.00	14,114,898	0.00%	(31.82)	NA
2007	-	-	0.00	110,257	0.00	(110,257)	0.00	17,201,865	0.00%	(1,283.18)	NA
2008	-	-	0.00	124,370	0.00	(124,370)	0.00	18,220,551	0.00%	(2,694.71)	NA
2009	-	-	0.00	-	0.00	-	0.00	21,200,706	0.00%	(2,662.89)	NA
2010	-	-	0.00	-	0.00	-	0.00	23,321,657	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	29,438,496	0.00%	NA	NA
TOTAL (15)	8,811	-	0.00	258,024	2,928.44	(258,024)	(2,928.44)	29,438,496	0.03%		

TO3 <> FERC Filing Detail for July 2007

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-359.2**
ACCOUNT - ROADS & TRAILS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1991	-	-	0.00	-	0.00	-	0.00				NA
1992	-	-	0.00	-	0.00	-	0.00				NA
1993	-	-	0.00	-	0.00	-	0.00				NA
1994	-	-	0.00	-	0.00	-	0.00				NA
1995	-	-	0.00	-	0.00	-	0.00			NA	NA
1996	-	-	0.00	-	0.00	-	0.00			NA	NA
1997	-	-	0.00	-	0.00	-	0.00			NA	NA
1998	-	-	0.00	-	0.00	-	0.00			NA	NA
1999	-	-	0.00	-	0.00	-	0.00			NA	NA
2000	-	-	0.00	-	0.00	-	0.00			NA	NA
2001	-	-	0.00	-	0.00	-	0.00			NA	NA
2002	-	-	0.00	-	0.00	-	0.00			NA	NA
2003	-	-	0.00	-	0.00	-	0.00			NA	NA
2004	-	-	0.00	-	0.00	-	0.00			NA	NA
2005	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%	NA	NA
Totals	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY
DETERMINATION OF SALVAGE VALUES FOR ACCOUNT **E-359.2**
ACCOUNT - ROADS & TRAILS PLANT - ELECTRIC TRANSMISSION
HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAND FNS % (K)	SHRINKING BAND FNS % @2011 (L)
1997	-	-	0.00	-	0.00	-	0.00				NA
1998	-	-	0.00	-	0.00	-	0.00				NA
1999	-	-	0.00	-	0.00	-	0.00				NA
2000	-	-	0.00	-	0.00	-	0.00				NA
2001	-	-	0.00	-	0.00	-	0.00			NA	NA
2002	-	-	0.00	-	0.00	-	0.00			NA	NA
2003	-	-	0.00	-	0.00	-	0.00			NA	NA
2004	-	-	0.00	-	0.00	-	0.00			NA	NA
2005	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%	NA	NA
2006	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%	NA	NA
2007	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%	NA	NA
2008	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%	NA	NA
2009	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%	NA	NA
2010	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%	NA	NA
TOTAL (15)	-	-	0.00	-	0.00	-	0.00	4,426,863	0.00%		

TO4 FERC <> 2013

SAN DIEGO GAS AND ELECTRIC COMPANY

DETERMINATION OF SALVAGE VALUES FOR ACCOUNT E-359.60

ACCOUNT - **Sunrise** ROADS & TRAILS - SRPL PLANT - ELECTRIC TRANSMISSION

HISTORICAL DATA BASE

YEAR (A)	PLANT RETIRED (B)	GROSS SALVAGE (C)	% OF RFS (D) (C) / (B)	COST OF REMOVAL (E)	% OF RFS (F) (E) / (B)	NET SALVAGE (G) (C) - (E)	% OF RFS (H) (G) / (B)	CURRENT PLANT (I)	% OF RFS TO CURRENT PLANT (J) (B) / (I)	5-YEAR ROLLING BAI FNS % (K)	SHRINKING BAND INS % @2011 (L)
2010	-	-	0.00	-	0.00	-	0.00	38,468	0.00%	NA	NA
2011	-	-	0.00	-	0.00	-	0.00	177,218	0.00%	NA	NA
TOTAL (2)	-	-	0.00	-	0.00	-	0.00	177,218	0.00%		

APPENDIX "C"

COR VS ACTUAL REMOVAL STUDY DETAIL

TO4 ANALYSIS

APPENDIX "C"

All FERC ACCOUNTS (Period July 1st 2007 thru December 2012)

YEAR (A)	PLANT RETIRED (B)	ACTUAL REMOVAL COST (C)	GROSS SALVAGE (D)	NET SALVAGE (GS less REM) (C - D) (E)	COR IN RATES (F)	DIFFERENCE (COR less NET SALVAGE) (F - E) (G)
2007	8,763,776*	2692863**	-	2,692,863	4,444,028	1,751,165
2008	5,047,658	6,205,207	-	6,205,207	9,435,167	3,229,959
2009	6,010,000	12,433,857	871,432	11,562,425	10,493,752	-1,068,673
2010	11,559,893	9,632,555	-1,062	9,633,617	11,478,946	1,845,329
2011	5,608,148	15,047,902	2,802,409	12,245,493	12,681,908	436,415
2012	2,845,417	6,971,166	800,852	6,170,314	19,584,316	13,414,002
	39,834,892	52,983,550	4,473,631	48,509,919	68,118,116	19,608,197
	========	========	========	========	========	========
	* full year retirements	**Six (6) Mnths Act Rem				
		Without Sunrise (2012 activity)>>		48,512,127	62,140,994	13,628,867

22 Year Summary - Act Net Salvage

YEAR	PLANT Assets Retired	Actual Net Salvage	Individual Year's Ratio
1991	2,279,601	628,302	-27.56%
1992	582,876	878,602	-150.74%
1993	1,513,570	728,329	-48.12%
1994	1,335,188	387,468	-29.02%
1995	2,847,125	367,003	-12.89%
1996	778,819	573,368	-73.62%
1997	546,865	469,284	-85.81%
1998	843,994	651,757	-77.22%
1999	4,250,671	1,688,052	-39.71%
2000	1,544,295	2,798,483	-181.21%
2001	3,670,776	2,760,832	-75.21%
2002	3,931,278	3,244,874	-82.54%
2003	3,106,512	3,061,545	-98.55%
2004	6,432,400	3,394,713	-52.78%
2005	6,422,321	4,497,059	-70.02%
2006	9,793,181	2,757,009	-28.15%
2007	8,763,776	3,479,045	-39.70%
2008	5,047,658	6,205,208	-122.93%
2009	6,010,000	11,562,425	-192.39%
2010	11,559,893	9,633,617	-83.34%
2011	5,608,148	12,245,493	-218.35%
2012	2,845,417	6,170,314	-216.85%
	GROUPINGS		
22 Years	89,714,363	78,182,781	-87.15%
20 Years	86,851,886	76,675,877	-88.28%
15 years	79,830,319	74,150,424	-92.89%
10 years	65,589,306	63,006,426	-96.06%
5 years	31,071,116	45,817,057	-147.46%

APPENDIX "D"

PROPOSED RATES vs AUTHORIZED RATES DETAIL

SPECIFIC DATE TO4 ANALYSES

COMPARISONS TO OTHER CA UTILITIES

San Diego Gas & Electric Company

TO3 Settlement Authorized Rates

Applied against TO3 settlement plant balances at 12/31/2005

A	Asset Class B	Class Description C	Gross Plant 12/31/2005 D Reported	Iowa Curves E	Fut. Net Salvg. % F Study	Fut.Net Salvage G =D * E/100	Depreciation Reserve H Reported	Net Balance I =A-F+G	Rem Life J Study	Avg Life K Study	Accrual L =H / I	Accrual Rate M =K / D
352	E0135210	Struct & Imprv-Other	58,592,677	R3	-30	-17,577,803	-17,171,374	58,999,106	38.4	50	1,536,435	0.0262
352	E0135220	Struct & Improv-SWPL	10,189,341	SQ	-30	-3,056,802	-6,656,229	6,589,914	29.3	50	224,912	0.0221
352 Total			68,782,018			-20,634,605	-23,827,603	65,589,020			1,761,347	
353	E0135310	Station Equip.-Other	307,171,555	R2.5	-10	-30,717,156	-74,461,034	263,427,677	37.4	48	7,043,521	0.0229
353	E0135320	Station Equip.-SWPL	138,776,308	SQ	-10	-13,877,631	-34,587,831	118,066,108	35.7	48	3,307,174	0.0238
353 Total			445,947,863			-44,594,786	-109,048,865	381,493,784			10,350,695	
354	E0135410	Towers & Fxtrs-Other	34,024,284	SQ	-75	-25,518,213	-26,253,092	33,289,405	45.0	70	739,765	0.0217
354	E0135420	Towers & Fixtrs-SWPL	61,988,482	SQ	-75	-46,491,362	-44,350,749	64,129,095	48.5	70	1,322,249	0.0213
354 Total			96,012,766			-72,009,575	-70,603,841	97,418,500			2,062,014	
355	E0135510	Poles & Fixtrs-Other	95,277,179	R1.5	-80	-76,221,743	-31,409,416	140,089,506	33.5	42	4,181,776	0.0439
355	E0135520	Poles & Fixturs-SWPL	7,918,275	SQ	-80	-6,334,620	-6,635,145	7,617,750	20.5	42	371,598	0.0469
355 Total			103,195,454			-82,556,363	-38,044,561	147,707,256			4,553,374	
356	E0135610	Ovrhd Cnd & Dv-Other	135,394,778	SQ	-95	-128,625,039	-76,475,082	187,544,735	44.2	54	4,243,094	0.0313
356	E0135620	Ovrhd Cnd & Dev-SWPL	42,153,628	SQ	-95	-40,045,947	-54,481,087	27,718,488	32.8	54	845,076	0.0200
356 Total			177,548,406			-168,670,986	-130,956,169	215,263,223			5,088,169	
357	E0135700	Trans UG Conduit	40,817,077	SQ	-45	-18,367,685	-6,558,969	52,625,793	50.5	60	1,042,095	0.0255
357 Total			40,817,077			-18,367,685	-6,558,969	52,625,793			1,042,095	
358	E0135800	Trans UG Conductor	28,143,063	SQ	-10	-2,814,306	-9,304,687	21,652,682	27.7	50	781,685	0.0278
358 Total			28,143,063			-2,814,306	-9,304,687	21,652,682			781,685	
359	E0135910	Roads & Trails-Other	10,071,163	SQ	0	0	-2,479,055	7,592,108	48.1	60	157,840	0.0157
359	E0135920	Roads & Trails-SWPL	4,426,863	SQ	0	0	-1,926,503	2,500,360	38.5	60	64,944	0.0147
359 Total			14,498,026			0	-4,405,558	10,092,468			222,784	
Grand Total			974,944,673		-42%	-409,648,306	-392,750,253	991,842,726	38.4		25,862,163	0.0265

APPENDIX "D"

San Diego Gas & Electric Company

COMPARISON PURPOSES ONLY

TO4 Proposed ASL, Iowa Curves, & FNS%

Applied against TO3 settlement plant balances at 12/31/2005

A	Asset Class B	Class Description C	Gross Plant 12/31/2005 D Reported	Iowa Curves E	Fut. Net Salvg. % F Study	Fut.Net Salvage G =D * E/100	Depreciation Reserve H Reported	Net Balance I =A-F+G	Rem Life J Study	Avg Life K Study	Accrual L =H / I	Accrual Rate M =K / D
352	E0135210	Struct & Imprv-Other	58,592,677	R2	-60	-35,155,606	-17,171,374	76,576,909	60.4	72	1,267,830	0.0216
352	E0135220	Struct & Improv-SWPL	10,189,341	R2	-60	-6,113,605	-6,656,229	9,646,717	51.3	72	188,045	0.0185
352 Total			68,782,018			-41,269,211	-23,827,603	86,223,626			1,455,875	
353	E0135310	Station Equip.-Other	307,171,555	R1	-60	-184,302,933	-74,461,034	417,013,454	39.4	50	10,584,098	0.0345
353	E0135320	Station Equip.-SWPL	138,776,308	R1	-60	-83,265,785	-34,587,831	187,454,262	37.7	50	4,972,262	0.0358
353 Total			445,947,863			-267,568,718	-109,048,865	604,467,716			15,556,359	
354	E0135410	Towers & Fxtrs-Other	34,024,284	R5	-100	-34,024,284	-26,253,092	41,795,476	45.0	70	928,788	0.0273
354	E0135420	Towers & Fixtrs-SWPL	61,988,482	R5	-100	-61,988,482	-44,350,749	79,626,215	48.5	70	1,641,778	0.0265
354 Total			96,012,766			-96,012,766	-70,603,841	121,421,691			2,570,566	
355	E0135510	Poles & Fixtrs-Other	95,277,179	R1.5	-100	-95,277,179	-31,409,416	159,144,942	36.5	45	4,360,135	0.0458
355	E0135520	Poles & Fixturs-SWPL	7,918,275	R1.5	-100	-7,918,275	-6,635,145	9,201,405	23.5	45	391,549	0.0494
355 Total			103,195,454			-103,195,454	-38,044,561	168,346,347			4,751,685	
356	E0135610	Ovrhd Cnd & Dv-Other	135,394,778	S0	-100	-135,394,778	-76,475,082	194,314,474	48.2	58	4,031,421	0.0298
356	E0135620	Ovrhd Cnd & Dev-SWPL	42,153,628	S0	-100	-42,153,628	-54,481,087	29,826,169	36.8	58	810,494	0.0192
356 Total			177,548,406			-177,548,406	-130,956,169	224,140,643			4,841,914	
357	E0135700	Trans UG Conduit	40,817,077	R5	-45	-18,367,685	-6,558,969	52,625,793	50.5	60	1,042,095	0.0255
357 Total			40,817,077			-18,367,685	-6,558,969	52,625,793			1,042,095	
358	E0135800	Trans UG Conductor	28,143,063	R3	-10	-2,814,306	-9,304,687	21,652,682	27.7	50	781,685	0.0278
358 Total			28,143,063			-2,814,306	-9,304,687	21,652,682			781,685	
359	E0135910	Roads & Trails-Other	10,071,163	SQ	0	0	-2,479,055	7,592,108	48.1	60	157,840	0.0157
359	E0135920	Roads & Trails-SWPL	4,426,863	SQ	0	0	-1,926,503	2,500,360	38.5	60	64,944	0.0147
359 Total			14,498,026			0	-4,405,558	10,092,468			222,784	
Grand Total			974,944,673		-72%	-706,776,546	-392,750,253	1,288,970,966	41.3		31,222,964	0.0320

APPENDIX "D"

San Diego Gas & Electric

COMPARISON PURPOSES ONLY

TO4 Proposed ASL, Iowa Curves, & FNS%

Applied against Plant balances at 12/31/2011

4010 Electric Transmission		Hist Plant Balance	Iowa Curve	Proposed FNS%	Proposed FNS $$$ =C*E	Recorded Accum Depr	Proposed Net Balance =C-G+H	Estimated Proposed RL =K+(N-M)	Proposed ASL "P"	Proposed Accrual = J / L	Proposed Rate = P / C	Proposed LIFE Accrual	Proposed LIFE Rate = P / C	Proposed COR Accrual	Proposed COR Rate = P / C
E0135210	Struct & Imprv-Other	102,586,460	R2	-60	-61,551,876	-26,973,023	137,165,313	61.30	72	2,237,607	0.0218	1,398,504	0.0136	839,103	0.0082
E0135220	Struct & Improv-SWPL	10,354,490	R2	-60	-6,212,694	-7,363,240	9,203,944	54.70	72	168,262	0.0163	105,164	0.0102	63,098	0.0061
E0135260	Struct & Improv-SRPL	1,268,807	R2	-60	-761,284	-11,097	2,018,994	71.70	72	28,159	0.0222	17,599	0.0139	10,560	0.0083
E352	**Total**	**114,209,757**		**-60**	**-68,525,854**	**-34,347,360**	**148,388,251**	**60.96**	**72**	**2,434,028**	**0.0213**	**1,521,268**	**0.0133**	**912,761**	**0.0080**
E0135310	Station Equip.-Other	520,112,885	R1	-60	-312,067,731	-97,442,372	734,738,244	40.30	50	18,231,718	0.0351	11,394,824	0.0219	6,836,894	0.0131
E0135320	Station Equip.-SWPL	171,254,190	R1	-60	-102,752,514	-47,932,800	226,073,904	33.50	50	6,748,475	0.0394	4,217,797	0.0246	2,530,678	0.0148
E0135340	Station Equip - Palomar	1,600,000	R1	-60	-960,000	-278,443	2,281,557	44.00	50	51,854	0.0324	32,408	0.0203	19,445	0.0122
E0135360	Station Equip.-SRPL	18,635,181	R1	-60	-11,181,109	-184,809	29,631,481	49.60	50	597,409	0.0321	373,381	0.0200	224,028	0.0120
E353	**Total**	**711,602,256**		**-60**	**-426,961,354**	**-145,838,424**	**992,725,186**	**38.73**	**50**	**25,629,455**	**0.0360**	**16,018,410**	**0.0225**	**9,611,046**	**0.0135**
E0135410	Towers & Fxtrs-Other	48,087,326	R5	-100	-48,087,326	-31,235,783	64,938,869	43.00	70	1,510,206	0.0314	755,103	0.0157	755,103	0.0157
E0135420	Towers & Fixtrs-SWPL	61,988,482	R5	-100	-61,988,482	-53,397,970	70,578,994	43.10	70	1,637,564	0.0264	818,782	0.0132	818,782	0.0132
E0135460	Towers & Fixtrs-SRPL	111,180	R5	-100	-111,180	-3,596	218,764	68.10	70	3,212	0.0289	1,606	0.0144	1,606	0.0144
E354	**Total**	**110,186,988**		**-100**	**-110,186,988**	**-84,637,349**	**135,736,627**	**43.08**	**70**	**3,150,982**	**0.0286**	**1,575,491**	**0.0143**	**1,575,491**	**0.0143**
E0135510	Poles & Fixtrs-Other	223,792,702	R1.5	-100	-223,792,702	-37,081,672	410,503,732	39.30	45	10,445,388	0.0467	5,222,694	0.0233	5,222,694	0.0233
E0135520	Poles & Fixturs-SWPL	8,106,560	R1.5	-100	-8,106,560	-8,851,665	7,361,455	17.90	45	411,254	0.0507	205,627	0.0254	205,627	0.0254
E0135560	Poles & Fixturs-SRPL	593,809	R1.5	-100	-593,809	-3,370	1,184,248	43.90	45	26,976	0.0454	13,488	0.0227	13,488	0.0227
E355	**Total**	**232,493,071**		**-100**	**-232,493,071**	**-45,936,707**	**419,049,435**	**38.50**	**45**	**10,883,618**	**0.0468**	**5,441,809**	**0.0234**	**5,441,809**	**0.0234**
E0135610	Ovrhd Cnd & Dv-Other	243,805,493	S0	-100	-243,805,493	-103,988,651	383,622,335	49.20	58	7,797,202	0.0320	3,898,601	0.0160	3,898,601	0.0160
E0135620	Ovrhd Cnd & Dev-SWPI	42,153,628	S0	-100	-42,153,628	-62,384,893	21,922,363	31.00	58	707,173	0.0168	353,587	0.0084	353,587	0.0084
E0135660	Ovrhd Cnd & Dev-SRPL	1,612,791	S0	-100	-1,612,791	-8,621	3,216,961	56.90	58	56,537	0.0351	28,269	0.0175	28,269	0.0175
E356	**Total**	**287,571,912**		**-100**	**-287,571,912**	**-166,382,165**	**408,761,659**	**47.75**	**58**	**8,560,912**	**0.0298**	**4,280,456**	**0.0149**	**4,280,456**	**0.0149**
E0135700	Trans UG Conduit	136,576,747	R5	-45	-61,459,536	-22,230,802	175,805,481	53.00	60	3,317,085	0.0243	2,287,645	0.0167	1,029,440	0.0075
E0135760	UG Conduit-SRPL	150,715	R5	-45	-67,822	-2,962	215,575	59.10	60	3,648	0.0242	2,516	0.0167	1,132	0.0075
E357	**Total**	**136,727,462**		**-45**	**-61,527,358**	**-22,233,764**	**176,021,056**	**53.01**	**60**	**3,320,732**	**0.0243**	**2,290,160**	**0.0167**	**1,030,572**	**0.0075**
E0135800	Trans UG Conductor	125,485,230	R3	-10	-12,548,523	-24,469,970	113,563,783	43.30	50	2,622,720	0.0209	2,384,291	0.0190	238,429	0.0019
E0135860	UG Cond. & Dev-SRPL	307,441	R3	-10	-30,744	-4,608	333,577	49.30	50	6,766	0.0220	6,151	0.0200	615	0.0020
E358	**Total**	**125,792,671**		**-10**	**-12,579,267**	**-24,474,578**	**113,897,360**	**43.32**	**50**	**2,629,486**	**0.0209**	**2,390,442**	**0.0190**	**239,044**	**0.0019**
E0135910	Roads & Trails-Other	29,438,496	SQ	0	0	-4,149,671	25,288,825	52.00	60	486,324	0.0165	486,324	0.0165	0	0.0000
E0135920	Roads & Trails-SWPL	4,426,863	SQ	0	0	-2,350,817	2,076,046	32.50	60	63,878	0.0144	63,878	0.0144	0	0.0000
E0135960	Roads & Trails-SRPL	177,218	SQ	0	0	-1,559	175,659	59.40	60	2,957	0.0167	2,957	0.0167	0	0.0000
E359	**Total**	**34,042,577**		**0**	**0**	**-6,502,047**	**27,540,530**	**49.79**	**60**	**553,159**	**0.0162**	**553,159**	**0.0162**	**0**	**0.0000**
Total Electric Transmission		1,752,626,694		-68	-1,199,845,804	-530,352,394	2,422,120,104	42.37		57,162,374	$\boxed{0.0326}$	33,932,341	$\boxed{0.0194}$	23,230,033	$\boxed{0.0133}$

APPENDIX "D"

SDG&E

COMPUTATION OF DEPRECIATION RATE AS OF 05/31/2012 USING PROPOSED TO4 ASL, IOWA CURVES, & FNS

Replaced Sunrise May 2012 with July 2012 Plant Detail

		Plant Balance	Iowa Curve	FNS% TO4	FNS $	Reserve @ 5/2012	Net Balance	RL	ASL TO4	Annual Accrual	Annual Rate	LIFE Accrual	LIFE Rate	COR Accrual	COR Rate
4010 Electric Transmission															
E0135210	Struct & Imprv-Other	103,321,004	R2	-60	-61,992,602	-28,218,034	137,095,572	61.00	72	2,247,468	0.0218	1,404,668	1.36%	842,801	0.82%
E0135220	Struct & Improv-SWPL	10,354,490	R2	-60	-6,212,694	-7,458,588	9,108,596	54.30	72	167,746	0.0162	104,841	1.01%	62,905	0.61%
E0135260	Struct & Improv-SRPL	172,010,175	R2	-60	-103,206,105	-589,045	274,627,235	71.70	72	3,830,226	0.0223	2,393,892	1.39%	1,436,335	0.84%
E352	**Total**	**285,685,669**		-60	**-171,411,401**	**-36,265,667**	**420,831,403**	**67.52**	72	**6,245,441**	0.0219	**3,903,400**	0.0137	**2,342,040**	0.0082
E0135310	Station Equip.-Other	526,286,634	R1	-60	-315,771,980	-100,467,651	741,590,963	40.00	50	18,539,774	0.0352	11,587,359	2.20%	6,952,415	1.32%
E0135320	Station Equip.-SWPL	171,040,205	R1	-60	-102,624,123	-49,514,645	224,149,683	32.60	50	6,875,757	0.0402	4,297,348	2.51%	2,578,409	1.51%
E0135340	Station Equip.-Palomar	1,600,000	R1	-60	-960,000	-293,710	2,266,290	43.60	50	51,979	0.0325	32,487	2.03%	19,492	1.22%
E0135360	Station Equip.-SRPL	259,531,508	R1	-60	-155,718,905	-1,098,242	414,152,171	49.60	50	8,349,842	0.0322	5,218,651	2.01%	3,131,191	1.21%
E353	**Total**	**958,458,347**		-60	**-575,075,008**	**-151,374,248**	**1,382,159,107**	**41.27**	50	**33,817,353**	0.0353	**21,135,845**	0.0221	**12,681,507**	0.0132
E0135410	Towers & Fxtrs-Other	48,030,871	R5	-100	-48,030,871	-31,668,929	64,392,813	42.80	70	1,504,505	0.0313	752,252	1.57%	752,252	1.57%
E0135420	Towers & Fixtrs-SWPL	61,988,482	R5	-100	-61,988,482	-53,948,118	70,028,846	42.60	70	1,643,870	0.0265	821,935	1.33%	821,935	1.33%
E0135460	Towers & Fixtrs-SRPL	546,888,337	R5	-100	-546,888,337	-1,808,643	1,091,968,031	68.10	70	16,034,773	0.0293	8,017,386	1.47%	8,017,386	1.47%
E354	**Total**	**656,907,690**		-100	**-656,907,690**	**-87,425,690**	**1,226,389,690**	**63.93**	70	**19,183,147**	0.0292	**9,591,574**	0.0146	**9,591,574**	0.0146
E0135510	Poles & Fixtrs-Other	236,056,933	R1.5	-100	-236,056,933	-40,664,821	431,449,045	39.30	45	10,978,347	0.0465	5,489,174	2.33%	5,489,174	2.33%
E0135520	Poles & Fixtures-SWPL	8,106,560	R1.5	-100	-8,106,560	-9,010,081	7,203,039	17.50	45	411,602	0.0508	205,801	2.54%	205,801	2.54%
E0135560	Poles & Fixtures-SRPL	7,540,396	R1.5	-100	-7,540,396	-98,338	14,982,454	43.90	45	341,286	0.0453	170,643	2.26%	170,643	2.26%
E355	**Total**	**251,703,889**		-100	**-251,703,889**	**-49,773,240**	**453,634,538**	**38.73**	45	**11,731,235**	0.0466	**5,865,618**	0.0233	**5,865,618**	0.0233
E0135610	Ovrhd Cnd & Dv-Other	250,322,704	S0	-100	-250,322,704	-107,068,676	393,576,732	49.10	58	8,015,819	0.0320	4,007,910	1.60%	4,007,910	1.60%
E0135620	Ovrhd Cnd & Dev-SWPL	42,978,735	S0	-100	-42,978,735	-62,741,284	23,216,186	30.60	58	758,699	0.0177	379,349	0.88%	379,349	0.88%
E0135660	Ovrhd Cnd & Dev-SRPL	103,927,022	S0	-100	-103,927,022	-541,605	207,312,439	56.90	58	3,643,452	0.0351	1,821,726	1.75%	1,821,726	1.75%
E356	**Total**	**397,228,461**		-100	**-397,228,461**	**-170,351,565**	**624,105,357**	**50.36**	58	**12,417,971**	0.0313	**6,208,985**	0.0156	**6,208,985**	0.0156
E0135700	Trans UG Conduit	142,407,774	R5	-45	-64,083,498	-23,722,351	182,768,921	52.90	60	3,454,989	0.0243	2,382,751	1.68%	1,072,238	0.75%
E0135760	UG Conduit-SRPL	152,068,584	R5	-45	-68,430,863	-468,411	220,031,036	59.10	60	3,723,029	0.0245	2,567,606	1.69%	1,155,423	0.76%
E357	**Total**	**294,476,358**		-45	**-132,514,361**	**-24,190,762**	**402,799,957**	**56.14**	60	**7,178,018**	0.0244	**4,950,358**	0.0168	**2,227,661**	0.0076
E0135800	Trans UG Conductor	125,760,006	R3	-10	-12,576,001	-25,934,340	112,401,667	42.90	50	2,620,085	0.0208	2,381,896	1.89%	238,190	0.19%
E0135860	UG Cond. & Dev-SRPL	198,091,177	R3	-10	-19,809,118	-563,392	217,336,903	49.30	50	4,408,456	0.0223	4,007,688	2.03%	400,769	0.20%
E358	**Total**	**323,851,183**		-10	**-32,385,118**	**-26,497,732**	**329,738,569**	**47.09**	50	**7,028,542**	0.0217	**6,389,584**	0.0197	**638,958**	0.0020
E0135910	Roads & Trails-Other	32,666,435	SQ	0	0	-4,356,090	28,310,345	52.40	60	540,274	0.0165	540,274	1.65%	0	0.00%
E0135920	Roads & Trails-SWPL	4,426,863	SQ	0	0	-2,377,932	2,048,931	32.10	60	63,830	0.0144	63,830	1.44%	0	0.00%
E0135960	Roads & Trails-SRPL	148,841,116	SQ	0	0	-339,875	148,501,241	59.40	60	2,500,021	0.0168	2,500,021	1.68%	0	0.00%
E359	**Total**	**185,934,414**		0	**0**	**-7,073,897**	**178,860,517**	**57.43**	60	**3,104,124**	0.0167	**3,104,124**	0.0167	**0**	0.0000
TO4 Detail	**Total Elec Trans (May 2012) w/ Sunrise at July 2012**	**3,354,246,011**		**-66%**	**-2,217,225,929**	**-552,952,801**	**5,018,519,139**	**49.83**		**100,705,831**	0.0300	**61,149,488**	1.82%	**39,556,343**	1.18%
	ET without Sunrise	**1,765,347,696**		**-69%**	**-1,211,705,184**	**-547,445,250**	**2,429,607,630**	**41.98**		**57,874,745**	0.0328	**34,451,874**	1.95%	**23,422,870**	1.33%
	Sunrise at July 2012	**1,588,898,315**		**-63%**	**-1,005,520,745**	**-5,507,551**	**2,588,911,509**	**60.44**		**42,831,086**	0.0270	**26,697,613**	1.68%	**16,133,473**	1.02%

San Diego Gas & Electric Company <> Comparison to SCE & PG&E

SDG&E CURRENT TO3 2007
SDG&E PROPOSED TO4 2013

			San Diego Gas & Electric (SDG&E)						Southern California Edison (SCE)			Pacific Gas & Electric (PG&E)		
			Fut. Net Salvg. %		Avg Life		Iowa Curve		Fut. Net Salvg. %	Avg Life	Iowa Curve	Future Net Salvage % (FNS)	Average Service Life (ASL)	Iowa Curve
			Current	Proposed	Current	Proposed	Current	Proposed	Proposed	Proposed	Proposed	Proposed	Proposed	Proposed
		YEAR	2007	2013	2007	2013	2007	2013	2009	2009	2009	2012	2012	2012
		Tariff Order	TO3	TO4	TO3	TO4	TO3	TO4						
		FERC FILING							ER08-1343	ER08-1343	ER08-1343	TO14	TO14	TO14
FERC #	Asset Class	Description												
E352	E0135210	Struct & Imprv-Other	<30%>	<60>	50	72	R3	R2						
E352	E0135220	Struct & Improv-SWPL	<30%>	<60>	50	72	SQ	R2						
E352	E0135260	Struct & Improv-SRPL	N/A	<60>	N/A	72	N/A	R2						
		E352 Total	<30%>	<60%>	50	72	above	R2	<40%>	55	S3	<20%>	60	R4
E353	E0135310	Station Equip.-Other	<10%>	<60>	48	50	R2.5	R1						
E353	E0135320	Station Equip.-SWPL	<10%>	<60>	48	50	SQ	R1						
E353	E0135340	Station Equip.-Palomar	<10%>	<60>	48	50	SQ	R1						
E353	E0135360	Station Equip.-SRPL	N/A	<60>	N/A	50	N/A	R1						
		E353 Total	<10%>	<60%>	48	50	above	R1	<5%>	40	R1	<60%>	43	R2.5
E354	E0135410	Towers & Fxtrs-Other	<75%>	<100>	70	70	SQ	R5						
E354	E0135420	Towers & Fixtrs-SWPL	<75%>	<100>	70	70	SQ	R5						
E354	E0135460	Towers & Fixtrs-SRPL	N/A	<100>	N/A	70	N/A	R5						
		E354 Total	<75%>	<100%>	70	70	above	R5	<85%>	65	S3	<105%>	70	R5
E355	E0135510	Poles & Fixtrs-Other	<80%>	<100>	42	45	R1.5	R1.5						
E355	E0135520	Poles & Fixturs-SWPL	<80%>	<100>	42	45	SQ	R1.5						
E355	E0135560	Poles & Fixturs-SRPL	N/A	<100>	N/A	45	N/A	R1.5						
		E355 Total	<80%>	<100%>	42	45	above	R1.5	<85%>	45	R1.0	<80%>	48	R2
E356	E0135610	Ovrhd Cnd & Dv-Other	<95%>	<100>	54	58	SO	S0						
E356	E0135620	Ovrhd Cnd & Dev-SWPL	<95%>	<100>	54	58	SQ	S0						
E356	E0135660	Ovrhd Cnd & Dev-SRPL	N/A	<100>	N/A	58	N/A	S0						
		E356 Total	<95%>	<100%>	54	58	above	S0	<95%>	50	R4	<90%>	55	R4
E357	E0135700	Trans UG Conduit	<45%>	<45>	60	60	SQ	R5						
E357	E0135760	Trans UG Conduit - SRPL	N/A	<45>	N/A	60	N/A	R5						
		E357 Total	<45%>	<45%>	60	60	above	R5	<10%>	55	R3	0%	60	R5
E358	E0135800	Trans UG Conductor	<10%>	<10>	50	50	SQ	R3						
E358	E0135860	Trans UG Conductor - SRPL	N/A	<10>	N/A	50	N/A	R3						
		E358 Total	<10%>	<10%>	50	50	above	R3	<30%>	35	R3	0%	56	R5
E359	E0135910	Roads & Trails-Other	0%	0	60	60	SQ	SQ						
E359	E0135920	Roads & Trails-SWPL	0%	0	60	60	SQ	SQ						
E359	E0135960	Roads & Trails-SRPL	N/A	0	N/A	60	N/A	SQ						
		E359 Total	0%	0%	60	60	above	SQ	0%	60	SQ	<10%>	60	R2.5

APPENDIX "D"

VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

Robert J. Wieczorek, being duly sworn, on oath, says that he is the Robert J. Wieczorek identified in the foregoing prepared direct testimony; that he prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Robert J. Wieczorek

Robert J. Wieczorek

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 11th day of February, 2013 before me, Rosalinda Rossi, a Notary Public, personally appeared Robert J. Wieczorek, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

ROSALINDA ROSSI
COMM. #1858772
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jul 24, 2013
LS01

Rosalinda Rossi

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

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

SAN DIEGO GAS & ELECTRIC COMPANY

EXHIBIT NO. SDG-9 (RAM)

#273980

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EXHIBITS

Exhibit No. SDG-9-1 (RAM-1)	Resume of Roger A. Morin
Exhibit No. SDG-9-2 (RAM-2)	Investment-Grade Integrated Electric Utilities DCF Analysis: Value Line Growth Projections
Exhibit No. SDG-9-3 (RAM-3)	Investment-Grade Integrated Electric Utilities DCF Analysis: Analysts' Growth Forecasts
Exhibit No. SDG-9-4 (RAM-4)	Western Electric Utilities DCF Analysis: Value Line Growth Forecasts
Exhibit No. SDG-9-5 (RAM-5)	Western Electric Utilities DCF Analysis: Analysts' Growth Forecasts
SDG-9-6 (RAM-6)	Electric Utility Beta Estimates
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Exhibit No. SDG-9-10 (Appendix A)	CAPM, Empirical CAPM
Exhibit No. SDG-9-11 (Appendix B)	Flotation Cost Allowance

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

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

INTRODUCTION AND SUMMARY

Q1. Please state your name, address, and occupation.

A1. 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").

Q2. Please describe your educational background.

A2. 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.

Q3. Please summarize your academic and business career.

A3. 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, and I am currently a faculty member of The Management Exchange Inc. and Exnet, Inc. (now SNL Center for Financial Education

LLC or "SNL"), 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 The Management Exchange Inc. and the SNL Center for Financial Education.

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 <u>The Journal of Finance</u>, <u>The Journal of Business Administration</u>, <u>International Management Review</u>, and <u>Public Utilities Fortnightly</u>. I published a widely-used treatise on regulatory finance, <u>Utilities' Cost of Capital</u>, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released my book, <u>Regulatory Finance</u>, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, <u>The New Regulatory Finance</u>, 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 RAM-1 describes my professional credentials in more detail.

Q4. Have you previously testified on cost of capital before utility regulatory commissions?

A4. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North America, including the Federal Energy Regulatory Commission ("FERC" or "Commission"), and the Federal Communications Commission. I have also 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	Washington
FCC	Minnesota	Ohio	West Virginia
FERC	Mississippi	Oklahoma	Nebraska

The details of my participation in regulatory proceedings are provided in Exhibit RAM-1.

Q5. What is the purpose of your testimony in this proceeding?

A5. The purpose of my testimony in this proceeding is to recommend a return on common equity ("ROE") for the jurisdictional electric transmission operations of the San Diego Gas and Electric Company ("SDG&E" or the "Company"). 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 consistent with the Commission's policy objectives. I will testify in this proceeding as to that opinion.

Q6. Please briefly identify the exhibits and appendices accompanying your testimony.

A6. I have attached to my testimony Exhibit RAM-1 through Exhibit RAM-9, 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.

Q7. Please summarize your findings concerning SDG&E's cost of common equity.

A7. Based on the results of various methodologies, current capital market conditions, and current economic industry conditions, I recommend the adoption of a ROE of 11.3%. This recommended ROE is based on SDG&E's common equity ratio of 52% as referenced by Ms. Hrna. A ROE of 11.3% 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.

In reaching this conclusion, I have employed the traditional cost of capital estimating methodologies which assume business-as-usual circumstances, and then performed a risk adjustment in order to account for SDG&E's 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 DCF, Risk Premium, and Capital Asset Pricing Model ("CAPM"), to two surrogates for SDG&E. They are: (1) a group of investment-grade dividend-paying electric utilities, and (2) a group consisting of Value Line's Western Electric Utilities. The 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 results from the various methodologies were adjusted upward by a 50 basis points to account for SDG&E's higher than average investment risk compared to other regulated utilities as evidenced by its higher than average beta risk measure. Following FERC policy, my base ROE was also adjusted upward by an additional 50 basis points incentive adder to recognize the Company's continuing participation in a regional transmission organization.

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's higher than average investment risk. Moreover, my recommended return is predicated on the assumption that the Company's manages the common equity percentage at 52%.

Q8. Would it be in the best interests of ratepayers for the commission to adopt your recommended 11.3% ROE for SDG&E's electricity transmission utility operations?

A8. Yes. My analysis shows that a ROE of 11.3% 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 over the long-term horizon since it would lower cash flows and credit metrics which would then translate to higher financing costs in the future.

Q9. Please explain how lower authorized ROEs can increase both the future cost of equity and debt financing.

A9. 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 just and reasonable authorized ROE of 11.3% 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.

Q10. Please describe how your testimony is organized.

A10. 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.

I. REGULATORY FRAMEWORK AND RATE OF RETURN

Q11. Please explain how a regulated company's rates should be set under traditional cost of service regulation.

A11. 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 just 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.

Q12. What fundamental principles underlie the determination of a just and reasonable ROE?

A12. 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.

Q13. How is the fair rate of return determined?

A13. 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.

Q14. How does the concept of a fair return relate to the concept of opportunity cost?

A14. 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.

Q15. What economic and financial concepts have guided your assessment of the company's cost of common equity?

A15. 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.

Q16. How does the company obtain its capital and how is its overall cost of capital determined?

A16. 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).

Q17. What is the market required rate of return on equity capital?

A17. 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.

Q18. What must be considered in estimating a fair ROE?

A18. 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.

II. COST OF EQUITY CAPITAL ESTIMATES

Q19. Dr. Morin, how did you estimate the fair ROE for SDG&E?

A19. I employed three methodologies: (1) the DCF methodologies, (2) the Risk Premium, and (3) the CAPM. 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 applied the aforementioned methodologies to two portfolios of electric utilities as reference groups for SDG&E.

Q20. Why did you use more than one approach for estimating the cost of equity?

A20. 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.

Q21. Are there any practical difficulties in applying cost of capital methodologies in the current environment of volatility in capital markets and economic uncertainty?

A21. 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 highly uncertain economy both in the U.S. and abroad. This is not only because stock prices are extremely volatile at this time, 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 the sluggish economy, restructuring, 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.

A. DCF Estimates

Q22. Please describe the DCF approach to estimating the cost of equity capital.

A22. 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.

Q23. How did you estimate SDG&E's cost of equity with the DCF model?

A23. I applied the DCF model to two proxies for SDG&E: (1) a group of investment-grade, dividend-paying, combination electric and gas utilities, and (2) a group consisting of the electric utilities that make up Value Line's Western Electrics group. The proxy companies were required to have at least 50% of their revenues from regulated operations.

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).

Q24. How did you estimate the dividend yield component of the DCF model?

A24. 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 the December 2012 edition of the Value Line Investment Analyzer ("VLIA") on-line data base. 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.

Q25. Why did you multiply the current dividend yield by (1 + g) rather than by (1 + 0.5g)?

A25. 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.

Q26. How did you estimate the growth component of the DCF model?

A26. 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 Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. The latter are also provided in the Value Line software. I also used Value Line's growth forecasts as additional proxies.

Q27. Why did you reject the use of historical growth rates in applying the DCF model to electric utilities?

A27. 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.

Q28. Did you consider any other method of estimating expected growth to apply the DCF model?

A28. 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

Q29. Do you have any reservations in regards to the sustainable growth method?

A29. 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.

Q30. Did you consider dividend growth in applying the DCF model?

A30. 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.

Q31. Is there any empirical evidence documenting the importance of earnings in evaluating investors' expectations?

A31. 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.

Q32. 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?

A32. 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.

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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.

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

Q33. Can you describe your first proxy group for SDG&E's utility business?

A33. As a first proxy for SDG&E, I examined a group of investment-grade dividend-paying combination electric and gas utilities, meaning that these companies all possess utility assets similar to SDG&E's. I began with all the companies designated as electric utilities by Value Line, that is, with Standard Industrial Classification codes 4911 to 4913. Foreign companies, private partnerships, private companies, non dividend-paying companies, companies undergoing a restructure or merger, and companies below investment-grade (with a Moody's bond rating below Baa3 as reported in AUS Utility Reports December 2012) 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 companies had to be designated "combination electric and gas utilities" as reported in AUS Utility Reports, December 2012 edition. The final group of

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[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.

[3] This is necessary in order to minimize the well-known thin trading bias in measuring beta.

28 companies, shown on Exhibit RAM-2, only includes those companies with at least 50% of their revenues from regulated utility operations.

I stress that this proxy group as well as the second group of proxy companies described below must be viewed as portfolios of comparable risk. It would be inappropriate to select any particular company or subset of companies from these groups and infer the cost of common equity from that company or subset alone.

Q34. What DCF results did you obtain for the combination electric and gas utility group using value line growth projections?

A34. Page 1 of Exhibit RAM-2 shows the raw dividend yield and growth input data for the 28 companies, while page 2 displays the DCF analysis. Ameren, Exelon, and Public Service Enterprise were eliminated on account of negative growth projections. As shown on Column 3, line 28 of page 2 of Exhibit RAM-2, the median[4] long-term earnings per share growth forecast obtained from Value Line is 5.00% for this group. Combining this growth rate with the median expected dividend yield of 4.53% shown in Column 4 produces an estimate of equity costs of 9.67% for the group shown in Column 5. Recognition of flotation costs brings the cost of equity estimate to 9.95%, shown in Column 6. The need for a flotation cost allowance is discussed at length later in my testimony. The average result is 10.28% and the midpoint 11.63%.

Q35. What DCF results did you obtain for the combination electric and gas utility group using the analysts' consensus growth forecast?

A35. From the original sample of 28 companies shown on page 1 of Exhibit RAM-3, Ameren, Exelon, and Public Service Enterprise were eliminated on account of negative growth rate projection. For the remaining 25 companies shown on page 2 of Exhibit RAM-3, using the consensus analysts' earnings growth forecast published by Zacks of 5.00% instead of the Value Line forecast, the cost of equity for the group is 9.58%, unadjusted

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[4] There are several measures of "averages" to calculate the central tendency of a sample of observations, including the mean, median, mode, midpoint, and truncated mean. The "mean" is the regular meaning "average", where you add up all the numbers and then divide by the number of observations. The "median" is the "middle" value in the list of numbers listed in numerical order. The "mode" is the value that occurs most often. The midpoint is simply the average of its endpoints, that is, the average of the maximum and minimum values. It is the point that is exactly between the two extreme high and low values. The truncated mean is obtained by removing the low and high estimates and averaging the remaining estimates.

for flotation cost. Recognition of flotation costs brings the cost of equity estimate to 9.85%, shown in Column 6, line 28. The average result is 10.08% and the midpoint 13.58%.

Q36. What DCF results did you obtain for value line's Western Electric Utility Group?

A36. As a second proxy for SDG&E, I examined a group consisting of the electric utilities that make up Value Line's Western Utility group. Several California electric utilities are included in this group, including SDG&E's parent company, Sempra Energy. Page 1 of Exhibit RAM-4 displays the electric utilities that make up the Western group, along with the input data for the DCF analysis. Page 2 of Exhibit RAM-4 displays the DCF analysis using Value Line growth projections. Edison was removed on account of its projected zero growth rate. As shown on column 2 of page 2 of Exhibit RAM-4, the median long-term growth forecast obtained from Value Line is 5.50% for this group. Coupling this growth rate with the average expected dividend yield of 4.36% shown in column 3 for each company produces a median estimate of equity costs of 9.79% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of column 4 brings the cost of equity estimate to 10.02%, as shown in column 5. The average result is 10.82% and the midpoint 12.61%.

Using the consensus analysts' growth forecast from Zacks instead of the Value Line growth forecast, the median cost of equity estimate for the group is 10.21%. The average result is 10.15% and the midpoint 12.24%. This analysis is displayed on pages 1 and 2 of Exhibit RAM-5.

Q37. Please summarize your DCF estimates.

A37. The table below summarizes the DCF estimates using the median, mean, and midpoint results:

<u>DCF STUDY</u>	Median ROE	Mean ROE	Midpoint ROE
Combination Elec & Gas Util Value Line Gth	9.9%	10.3%	11.6%
Combination Elec & Gas Util Zacks Grh	9.9%	10.1%	13.6%
Value Line Western Elec Util Value Line Gth	10.0%	10.8%	12.6%
Value Line Western Elec Util Zacks Grth	10.2%	10.2%	12.2%

I note that the mean and midpoint DCF results are substantially higher than the median results. In view of FERC's preference for the median, I shall rely on those results although I view them as bare-bone estimates, given the higher estimates produced by the other usual standard measures of central tendency.

Q38. Dr. Morin, please provide an overview of your risk premium analyses.

A38. 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 electric utility industry.

B. CAPM Estimates

Q39. Please describe your application of the CAPM risk premium approach.

A39. 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 4.7%, based on forecast interest rates on long-term U.S. Treasury bonds. For beta, I used 0.70

and for the MRP, I used 7.2% based on both historical and prospective studies. These inputs to the CAPM are explained below.

Q40. How did you arrive at your risk-free rate estimate of 4.7% in your CAPM and risk premium analyses?

A40. 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.

Q41. Why did you rely on long-term bonds instead of short-term bonds?

A41. 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.

Q42. Dr. Morin, are there other reasons why you reject short-term interest rates as proxies for the risk-free rate in implementing the CAPM?

A42. 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.

Q43. What is your estimate of the risk-free rate in applying the CAPM?

A43. 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 three prominent sources: Global Insight, Value Line, and Consensus Economics Inc.

30-YEAR TREASURY YIELD FORECASTS

	2014	2015	2016	2017
Global Insight	3.7	4.0	4.5	5.2
Value Line	3.4	4.0	4.5	
Consensus Econ.	3.4	4.4	5.1	5.4
AVERAGE	**3.5**	**4.1**	**4.7**	**5.3**

Global Insight forecasts a yield of 3.7% in 2014, 4.0% in 2015, 4.5% in 2016, and 5.2 in 2017, and 5.4% thereafter. Value Line's quarterly economic review for November 2012 forecasts a yield of 3.4% in 2014, 4.0% in 2015, and 4.5 in 2016. Consensus Economics Inc.'s October 2012 edition forecasts a yield of 3.4% in 2014 rising to 5.4% in 2017.[5] The average 30-year long-term bond yield forecast from the three sources is 3.5% in 2014, 4.1% in 2015, 4.7% in 2016, and 5.3% in 2017. The average over the 2015-2017 period is 4.7%. The rising yield forecasts are also consistent with the sharply upward-sloping yield curve observed at this time. Based on this consistent evidence, a long-term bond yield forecast of 4.7% 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. I deem this estimate conservative as interest rate forecasts call for even higher interest rates over the next several years in response to record high federal deficits, higher anticipated inflation, and eventual economic recovery.

[5] Global Insight forecasts are for 30-year bonds, while both Value Line and Consensus Economics forecasts are for 10-year bonds. 50 basis points were added to the 10-year forecasts based on the historical 50 basis points spread between 10 and 30-year yields.

Q44. 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?

A44. Two reasons. First, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. 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. *Morningstar* (formerly Ibbotson Associates) recognized the primacy of current expectations[6]:

> *The cost of capital is always an expectational or forward- looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.*

Second, the CAPM estimate is calibrated from investors' required risk premium between risk-free bonds and common stocks. However, in response to heightened uncertainties, following the 2008-2009 financial crisis, the continuing sovereign debt crises in Europe, and the anemic economic recovery here at home, investors have sought a safe haven in U.S. Treasury bonds, and this "flight to safety" has pushed long-term government bond yields significantly lower.

Lower interest rates on long-term US Treasury bonds do not necessitate a commensurate decline in SDG&E's allowed ROE. This point of view fails to take into consideration several important and relevant factors. First, if the economy is improving, the current low level interest rate environment is only temporary as most interest rate forecasts attest, as shown earlier. Investors are aware that the U.S. central bank (Federal Reserve) is temporarily suppressing interest rates to encourage economic growth. Investors recognize that once central banks change their expansive monetary strategy when the economy rebounds, interest rates could increase quickly and borrowing costs could increase significantly.[7] In fact, as I showed earlier, interest rate forecasts and the

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6 Morningstar, *Ibbotson SBBI, 2011 Valuation Yearbook* at 21.

7 Morgan Stanley posits that likewise, "regulators appear to view the current interest rate environment as unsustainable, and as an indication of market instability and a flight from riskier assets." Morgan Stanley Research, "Regulated Utilities," (Jan. 7, 2012) at 11.

current shape of the yield curve indicate an expected surge in interest rates. Second, the fact that long-term government bond yields and utility bond yields are at historically low levels does not demonstrate that the cost of equity is likewise at historically low levels. Rather, the current low levels of long-term government bond yields are the result of investors' continued risk aversion and a "flight to quality."[8] Reduced interest rates on safe investments do not necessarily mean that equity market risks have decreased or that investors have materially reduced their return requirements. Despite the low interest rate climate, equity investors expect that their investments in utilities will provide adequate returns. Morgan Stanley Research reports:

> *While interest rates have fallen substantially, we believe regulators will lower ROEs only modestly….Relative to the significant move in Treasuries, the ROEs allowed by regulators have come down modestly. In our opinion, this is due to the 'long view' nature of utility regulators, as they prefer to set a return level indicative of longer-term required return levels.*[9]

Recognizing the impact the U.S. Federal Reserve's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, I believe that models that relate the investor-required return on equity to the yield on government securities, such as the CAPM approach, need to be implemented cautiously and recalibrated in order to produce realistic estimates of the ROE at this time.

"Flight to quality" can be shown graphically using the traditional CAPM model. A security market line is the relationship between the expected rate of return of a security and its systematic, non-diversifiable risk (beta). The initial security market line (dashed line) on the graph below has a risk-free rate *rf* and market risk premium of *MRP*. In a time of market uncertainty, investors flee to risk-free assets driving the price of *rf* down to *rf**. However, the market's level of uncertainty has increased driving the security market line *steeper* (dotted line). As such, there in increased market risk premium *(Δ MRP)*. This is why we see large risk premiums when interest rates are low as we do now.

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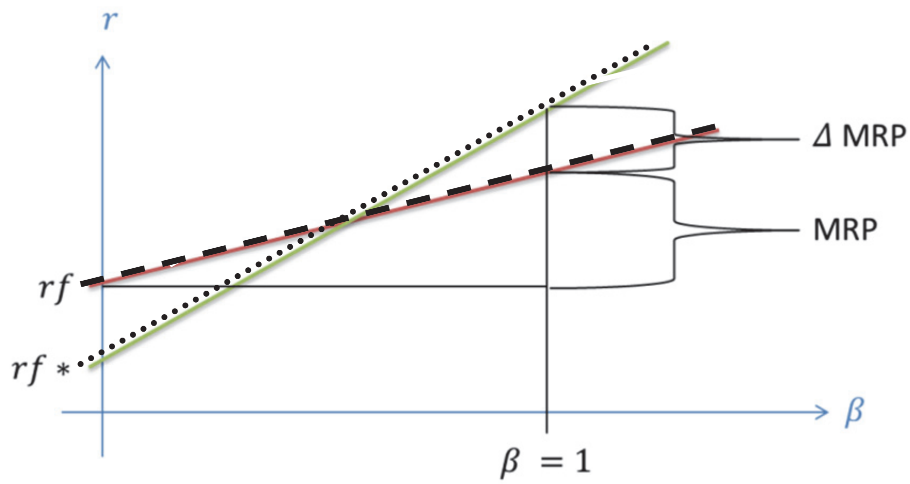
[8] Flight to quality refers to a sudden shift in investment behaviors in a period of financial turmoil where investors seek to sell assets perceived as risky and instead purchase safe assets.

[9] Morgan Stanley Research, "Regulated Utilities," (Jan. 7, 2012) at 11.



Q45. How did you select the beta for your CAPM analysis?

A45. 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, SDG&E is not publicly traded, and therefore, proxies must be used. In the discussion of DCF estimates of the cost of common equity earlier, I examined a sample of widely-traded investment-grade dividend-paying combination electric and gas utilities covered by Value Line that have (i) at least 50% of their revenues from regulated utility operations, and (ii) a market capitalization that is more than $1 billion. The median beta for this group is 0.70. Please see Exhibit RAM-6, page 1 for the betas of this sample of utilities.

I also examined the beta of the electric utilities that make up the two groups of reference companies. The median beta for both groups is 0.70, as shown on pages 1 and 2 of Exhibit RAM-6.

Based on these results, I shall use 0.70, as an estimate for the beta applicable to the average risk electric utility.

Q46. What MRP did you use in your CAPM analysis?

A46. For the MRP, I used 7.2%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums.

Q47. Can you describe the historical MRP study used in your CAPM analysis?

A47. Yes. The historical MRP estimate is based on the results obtained in the Morningstar (formerly Ibbotson Associates) study, *Stocks, Bonds, Bills, and Inflation, 2012 Yearbook*, which compiles historical returns from 1926 to 2011. This well-known study shows that a very broad market sample of common stocks outperformed long-term U.S. Government bonds by 5.7%. The historical MRP over the income component of long-term Government bonds rather than over the total return is 6.6%. Morningstar recommends the use of the latter as a more reliable estimate of the historical MRP, and I concur with this viewpoint. 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. This is because 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 (1926-2011) MRP (based on income returns, as required) is specifically calculated to be 6.6% rather than 5.7%.

Q48. On what maturity bond does the Morningstar historical risk premium data rely?

A48. Because 30-year bonds were not always traded or even available throughout the entire 1926-2011 period covered in the Morningstar 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 Morningstar study, the difference in yield is not material.

Q49. Why did you use long time periods in arriving at your historical MRP estimate?

A49. 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, at least prior to the onslaught of the financial crisis of 2008-2009 which has now partially subsided, that is, no significant serial correlation in the Morningstar study prior to that time, it is reasonable to assume that these quantities will remain stable in the future.

Q50. Should studies of historical risk premiums rely on arithmetic average returns or on geometric average returns?

A50. 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.[10]

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[10] *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).

Q51. Please explain how the issue of what is the proper "mean" arises in the context of analyzing the cost of equity?

A51. 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 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.

Q52. If both are "representative" of the series, what is the difference between the two?

A52. 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.

Q53. Can you provide a numerical example to illustrate this difference between geometric and arithmetic means?

A53. 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%):

GEOMETRIC VS. ARITHMETIC RETURNS

YEAR	STOCK A	STOCK B
2003	50.0%	11.6%
2004	-54.7%	11.6%
2005	98.5%	11.6%
2006	42.2%	11.6%
2007	-32.3%	11.6%
2008	-39.2%	11.6%
2009	153.2%	11.6%
2010	-10.0%	11.6%
2011	38.9%	11.6%
2012	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.

Q54. Can you describe the prospective MRP study used in your CAPM analysis?

A54. Yes. I applied a prospective DCF analysis to the aggregate equity market using Value Line's VLIA software. The computations are shown in Exhibit RAM-8. The dividend yield on the 7,698 stocks in the full Value Line database is currently 0.5%, and the average projected long-term growth rate is 11.7%. Adding the expected dividend yield to the growth component produces an expected market return on aggregate equities of 12.2%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the MRP estimate to approximately 12.4%. Subtracting the risk-free rate of 4.7% from the latter, the implied risk premium is 7.7% over long-term U.S. Treasury bonds. This estimate is slightly higher than the historical estimate of 6.6%. This is not surprising given the sharp repricing of risk in the investment community that followed the financial crisis of 2008-2009, and the continuing volatility in financial markets that have caused a fundamental upward shift in investors' risk aversion.

The average of the historical MRP of 6.6% and the prospective MRP of 7.7% is 7.2%, which is my final estimate of the MRP for purposes of implementing the CAPM.

Q55. Dr. Morin, is your MRP estimate of 7.2% consistent with the academic literature on the subject?

A55. Yes, it is, although in the upper portion of the range. In their authoritative corporate finance textbook, Professors Brealey, Myers, and Allen[11] 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.

Q56. What is your risk premium estimate of the average risk utility's cost of equity using the CAPM approach?

A56. Inserting those input values into the CAPM equation, namely a risk-free rate of 4.7%, a beta of 0.70, and a MRP of 7.2%, the CAPM estimate of the cost of common equity is:

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

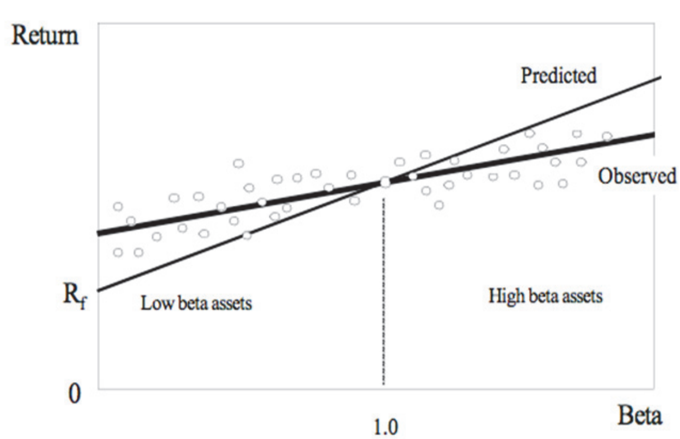
4.7% + 0.70 x 7.2% = 9.7%. This estimate becomes 10.0% with flotation costs, discussed later in my testimony.

Q57. Can you describe your application of the empirical version of the CAPM?

A57. 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:

$$K = R_F + \alpha + \beta \times (MRP - \alpha)$$

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:

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

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.[12] 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 4.7% for the risk-free rate R_F, a MRP of 7.2% for (R_M - R_F) and a beta of 0.70 in the above equation, the return on common equity is 10.3%. This estimate becomes 10.6% with flotation costs, discussed later in my testimony.

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[12] 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:

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

Q58. Is the use of the ECAPM consistent with the use of adjusted betas?

A58. 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.

Q59. Please summarize your CAPM estimates.

A59. The table below summarizes the common equity estimates obtained from the CAPM studies.

CAPM Method	ROE
Traditional CAPM	10.0%
Empirical CAPM	10.6%

C. Historical Risk Premium Estimate

Q60. Please describe your historical risk premium analysis of the electric utility industry using Treasury bond yields.

A60. A historical risk premium for the electric utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1930-2011 period, using *Standard and Poor's Utility Index* as an industry proxy. The analysis is depicted on Exhibit RAM-7. 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.

As shown on Exhibit RAM-7, the average risk premium over the period was 5.9% over long-term Treasury bond yields. Given the risk-free rate of 4.7%, and using the historical estimate of 5.9%, the implied cost of equity is 4.7% + 5.9% = 10.6% without flotation costs and 10.9% with the flotation cost allowance.

Q61. Dr. Morin, are risk premium studies widely used?

A61. Yes, they are. Risk Premium analyses are widely used by analysts, investors, economists, and expert witnesses. Most college-level corporate finance and/or investment management texts, including Investments by Bodie, Kane, and Marcus[13], 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[14], 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.

Q62. Are you concerned about the realism of the assumptions that underlie the historical risk premium method?

A62. 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 measured over short time periods. By

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[13] McGraw-Hill Irwin, 2002.

[14] Fourth edition, South-Western, 2011.

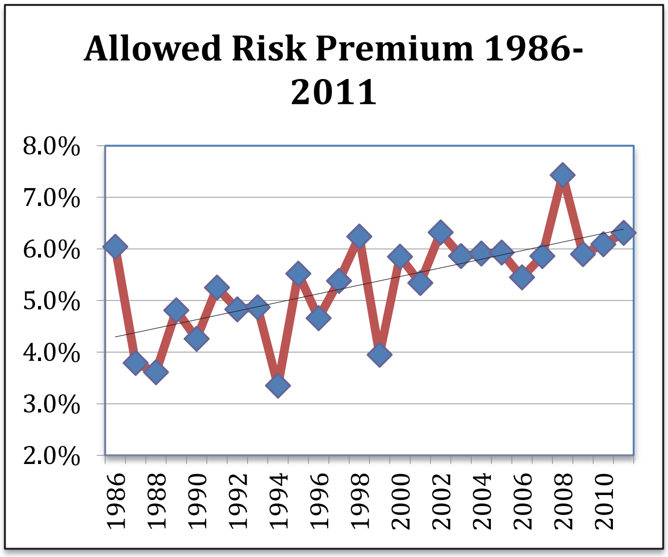
ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only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

D. Allowed Risk Premiums

Q63. Please describe your analysis of allowed risk premiums in the electric utility industry.

A63. 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 1986-2011 period for which data were available, relative to the contemporaneous level of the long-term Treasury bond yield. This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, Risk Premium, CAPM, *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 SNL) and easily verifiable from SNL publications and past commission decision archives.

The average ROE spread over long-term Treasury yields was 5.3% over the entire 1986-2011 period for which data were available from SNL. 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.

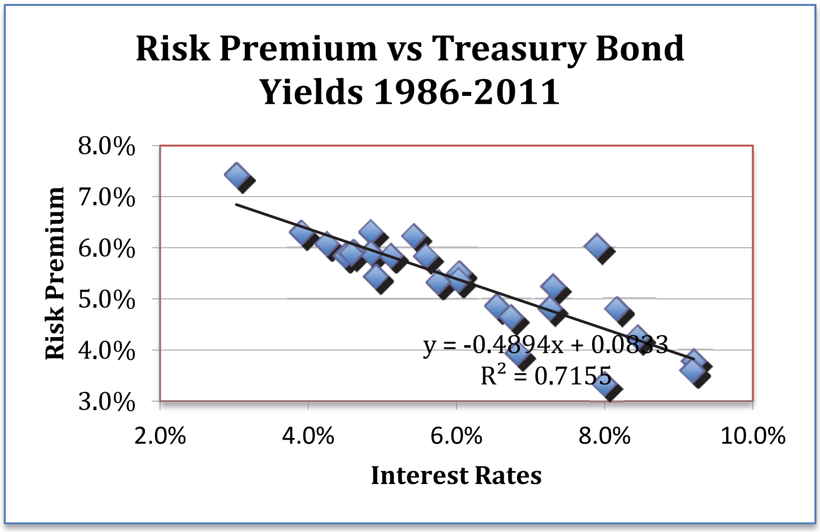


A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium ("RP") and interest rates ("YIELD") emerges over the 1986-2011 period:

$$RP = 8.3300 - 0.4894\ YIELD \qquad R^2 = 0.71$$

The relationship is highly statistically significant[15] 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.

[15] 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 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.



Inserting the current long-term Treasury bond yield of 4.7% in the above equation suggests a risk premium estimate of 6.0%, implying a cost of equity of 10.7%. This estimate is almost identical to the estimate of 10.8% obtained from the historical risk premium analysis.

I have also examined recent ROE awards by FERC for electric utilities. The data are shown in Exhibit RAM-10. The average allowed ROE in 2011-12 decisions is also 10.7%, identical to the previous estimate, and the average allowed risk premium inherent in those decisions is 7.2%. Given a projected risk-free rate of 4.7%, the implied cost of equity is 11.9%.

Q64. Do investors take into account allowed returns in formulating their return expectations?

A64. 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 SNL (formerly Regulatory Research Associates). 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.

Q65. Please summarize your risk premium estimates.

A65. The table below summarizes the ROE estimates obtained from the two risk premium studies.

Risk Premium Method **ROE**

Historical Risk Premium Electric	10.9%
Allowed Risk Premium	10.7%

D. Need for Flotation Cost Adjustment

Q66. Please describe the need for a flotation cost allowance.

A66. 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, including FERC. 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.

Q67. Dr. Morin, please elaborate on the market pressure component of flotation cost.

A67. 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.

Q68. Is a flotation cost adjustment required for an operating subsidiary like SDG&E that does not trade publicly?

A68. 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.

III. SUMMARY AND RECOMMENDATION ON COST OF EQUITY

Q69. Please summarize your results and recommendation.

A69. To arrive at my final recommendation, I performed DCF analyses on two surrogates for SDG&E: a group of investment-grade dividend-paying combination electric and gas utilities and a group of made up of Value Line's Western Electric group. I also performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from electric utility industry aggregate data, using the current yield on long-term utility bonds. The results are summarized in the table below.

STUDY	ROE
Traditional CAPM	10.0%
Empirical CAPM	10.6%

Hist. Risk Premium Elec Utility Industry	10.9%
Allowed Risk Premium	10.7%
DCF Combination Elec & Gas Utilities Value Line Growth	9.9%
DCF Combination Elec & Gas Utilities Zacks Growth	9.9%
DCF Value Line Western Electrics Value Line Growth	10.0%
DCF Value Line Western Electrics Zacks Growth	10.2%

The results range from 9.9% to 10.9% with a midpoint of 10.4%. The average result as well as the truncated average result is 10.3%. The median result is 10.1%. The results from the various methodologies are remarkably consistent, increasing the confidence in the reliability and reasonableness of the results. Based on those central results, I shall use 10.3% as my base ROE estimate for the average risk electric utility. I reiterate my earlier caution that the DCF results in the above table are very conservative, given that the other measures of central tendency produce substantially higher estimates.

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.

Q70. Should the cost of equity estimates be adjusted upward to account for SDG&E being more risky than the average electric utility?

A70. Yes, they should. The cost of equity estimates derived from the comparable groups 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 is downward-biased. In my judgment, a reasonable estimate of the risk differential is on the order of 50 basis points and I have adjusted my base ROE upward from 10.3% to 10.8% in order to account for SDG&E's higher relative risks, discussed below.

Q71. Do investors perceive SDG&E as a riskier than average electric utility?

A71. Yes, they do. SDG&E's parent company beta is 0.80 compared to the average beta of 0.73 for the Western electric utilities group, a difference of 0.07. 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.

Q72. How did you arrive at the 50 basis points adjustment?

A72. The 50 basis points adjustment is based on observed beta differentials. The CAPM formula was referenced to approximate the return (cost of equity) differences implied by the differences in the betas between the average electric utility company and SDG&E. The basic form of the CAPM, as discussed earlier, states that the return differential is given by the differential in beta times the MRP, (R_M - R_F). SDG&E's parent company's beta is 0.80 compared to the average beta of 0.73 for the Western electric utilities group. The return differential implied by the difference of 0.07 in beta is given by 0.07 times (R_M - R_F). Using an estimate of 7.2% for (R_M - R_F) as discussed earlier, the return adjustment is very close to 50 basis points.

Q73. Can you briefly discuss the principal aspects of SDG&E's business risk profile which differentiate the company from its peers?

A73. Yes. The rate of return must take into account the investment risk of the Company. The investment risk of a firm is comprised of its business risk and financial risk. Business risk refers to all risks that affect the relationship between revenues and expenses of a company excluding the effect of using debt to finance the assets of a company. An increase in business risk will depress the value of the security.

Financial risk reflects the risk of using debt to finance assets and its impact on the balance between revenues and costs. Interest, unlike dividends, must be paid even during adverse circumstances. As a result, when revenues decrease relative to costs, a leveraged company will incur a greater reduction in income than a non-leveraged company. Further, debt can expose companies to the risk of bankruptcy. An increase in financial leverage, or debt, and a resulting lower common equity ratio, will increase financial risk, and depress the price of the security.[16]

The Company faces several increased business risks relative to its peers, hence its higher beta risk measure. The principal risk factors very large transmission-related capital investments relative to the size of its rate base, and regulation/litigation. The Company's litigation risks and derivative regulatory risks are higher than those faced by other California utilities, and few if any other electric utilities confront the unique risk factors and challenges faced by SDG&E.

Q74. Can you comment on the company's business risks?

A74. Yes. Higher than average business risks result from several factors, including reduced demand in a weak economy, the Company's renewable-energy portfolio mandate, environmental compliance, and an ambitious capital expenditure program which will require approximately $6 billion dollar of financing over the next five years.

Q75. Can you comment on the company's business risks associated with transmission?

A75. 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. Transmission-related capital investments are expected to total $2 billion. To place this number in proper perspective, the Company's entire debt portfolio is approximately $4 billion. 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.

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[16] It is important to note that published debt/equity ratios generally do not account for the impact of the "debt equivalency" of firm purchased power obligations. Differences in firm purchased power obligations can impact the relative financial risk of electric utilities.

Q76. Does the Company's massive capital spending program increase its business risks?

A76. Yes, it does. The Company is projecting a capital need of nearly $6 billion for new utility infrastructure to improve reliability, including upgrades to its transmission system, to support growth, to enhance reliability, ease access to more generating resources, and to comply with strict Renewable Portfolio Standards (RPS) which are among the strictest in the nation. Construction of generation and transmission facilities will face many challenges due to public sentiment, politics, and permitting requirements. The processes to get all the approvals needed to install these capital additions take many years and therefore put investor funds at risk for extended periods. As shown by Company witness S. Hrna, SDG&E has a comparatively high level of expected capital investments compared to the proxy group of companies.

Further, the Company needs to support an increase in the base level of capital expenditures, as well as capital expenditures growing beyond traditional requirements, in order to support renewable investments and customer options. S&P has addressed electric utilities' rising capital expenditures in many of its reports. For example, in a report dated March 9, 2009, S&P cautioned that:

> *Slow recovery of costs could further impinge on its liquidity as short-term funds are consumed to finance high working-capital needs*." The report added that: "*In addition to fuel-cost recovery filings, regulators likely will have to be addressing significant rate increase requests related to new large generating capacity additions, infrastructure and reliability upgrades, and environmental modifications. Current cash recovery and/or return by means of construction work in progress may mitigate the significant cash flow drain and reduce the utility's need to issue debt securities during the construction cycle*", and *"[t]o the extent that utilities increase their capital budgets to address these needs, they will be highly dependent on electricity rate increases to sustain bondholder protection measures*.

Q77. Please comment on SDG&E's challenge to comply with California's strict renewables standards.

A77. 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.*[17]

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.

As discussed below in the discussion of financial risk, large obligations created by long term Power Purchase Agreements ("PPAs") will result in larger amounts of imputed debt (a.k.a. "debt equivalents"), which will negatively impact the Company's financial ratios as viewed by credit rating agencies and negatively impact credit quality.

Q78. Are there other material transmission-related business risks faced by the company?

A78. Yes, there are. As discussed in company witness S. Hrna's testimony, 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. Moreover, 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

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

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.

Q79. Are the company's financial risks above average?

A79. Yes, they are. Financial risk stems from the method used by the firm to finance its investments and is reflected in its capital structure. It refers to the additional variability imparted to income available to common shareholders by the employment of fixed cost financing, that is, debt capital. Although the use of fixed cost capital (debt and preferred stock) can offer financial advantages through the possibility of leverage of earnings, it creates additional risk due to the fixed contractual obligations associated with such capital. Debt carries fixed charge burdens which must be supported by the company's earnings before any return can be made available to the common shareholder. The greater the percentage of fixed charges in relation to the total income of the company, the greater the financial risk. The use of fixed cost financing introduces additional variability into the pattern of net earnings over and above that already conferred by business risk. Variations in operating earnings cause amplified variations in equity returns when debt financing is used. The spread in equity returns is wider in the case of debt financing, and the greater the leverage, the greater the spread and the greater the cost of common equity.

Q80. Dr. Morin, how do debt equivalents, such as purchased power contracts, affect SDG&E's financial risk profile?

A80. An electric utility with long-term PPAs possesses higher financial risks than a utility without such contracts, all else remaining constant. A company's obligations pursuant to long-term PPAs are comparable to long-term debt and are treated as such by investors and bond rating agencies. The same is true for leveraged lease arrangements.

The risk perceptions of the investment community and bond rating agencies are such that incremental long-term fixed obligations associated with acquiring energy through off-system purchases increase a utility's financial risk. Clearly, if a company's PPAs are converted to a debt equivalent, that company's effective debt ratio increases, and so does its risk.

Q81. Does financial theory provide a reasonable and consistent method of adjusting for the increased risk and return associated with debt equivalents?

A81. Yes, it does. The cost of equity for a company with substantial debt equivalents is higher because that company's effective leverage is higher than otherwise would be the case. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing and/or debt equivalents. In other words, the greater the effective debt ratio, the greater the return required by equity investors.

Several researchers have studied the empirical relationship between the cost of capital and effective capital-structure changes. Comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities are summarized in Chapter 17 of my book, <u>The New Regulatory Finance</u>.

The results of empirical studies and theoretical studies indicate that equity costs increase from as little as 34 to as much as 237 basis points when the debt ratio increases by ten percentage points. The average increase is 138 basis points from the theoretical studies and 76 basis points from the empirical studies, or a range of 7.6 to 13.8 basis points per one percentage point increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the effect on equity costs.

Q82. Can you provide a numerical example of the manner in which debt equivalents increase the cost of equity?

A82. Yes, I can. Consider an electric utility with a capital structure consisting of 50% debt capital and 50% common equity capital without any debt equivalents, and whose cost of common equity has been determined to be 11%. For illustrative purposes, let us assume that long-term purchased power contracts raise the company's effective debt ratio from 50% to 55%, indicating a significant increase in financial risk. An upward adjustment to the initial cost of common equity estimate of 11.0% would be required to reflect this additional risk. Since the capital structure difference amounts to 5%, that is, 55% - 50% = 5%, the required upward adjustment to the cost of equity ranges from 7.6 to 13.8 basis points times 5, which equals 38 to 69 basis points. The midpoint of this range is about 55 basis points. Therefore, in this particular example, the initial cost of equity of 11% would have to be adjusted upward by 55 basis points, raising the cost of equity from 11.00% to

11.55%, in order to reflect the weaker effective capital structure engendered by the purchased power contract debt equivalents.

Q83. How does the inclusion of debt equivalents affect SDG&E's debt ratio?

A83. As discussed in company witness S. Hrna's testimony, the imputed debt for SDG&E's will decrease its common equity capitalization ratio from 52% to approximately 44%, a substantial decrease that raises the Company's financial risk. The Company's request to increase its authorized common equity ratio to 52% only partially offsets the impact of increased debt equivalents.

Q84. Dr. Morin, what is your final conclusion regarding SDG&E's cost of common equity capital?

A84. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of SDG&E, it is my opinion that a just and reasonable ROE for SDG&E's jurisdictional electric transmission operations is 11.3%.

Q85. Dr. Morin, what capital structure assumption underlies your recommended return on SDG&E's common equity capital?

A85. My recommended return on common equity for SDG&E is predicated on the adoption of a test year capital structure consisting of 52% common equity capital.

Q86. Is there a relationship between authorized roe and financial risk?

A86. There certainly is. The strength of that relationship is amplified for smaller utilities like SDG&E. A low authorized ROE increases the likelihood the utility will have to rely increasingly on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns.

Q87. Is SDG&E's financial risk impacted by the authorized ROE?

A87. Yes, very much so. A low ROE increases the likelihood that SDG&E will have to rely on debt financing for its capital needs. As the Company relies more on debt financing, its capital structure becomes more leveraged. Since debt payments are a fixed financial obligation to the utility, this decreases the operating income available for dividend growth. Consequently, equity investors face greater uncertainty about the future dividend potential of the firm. As a result, the Company'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, or if so, at prohibitive costs.

Q88. If capital market conditions change significantly between the date of filing your prepared testimony and the date oral testimony is presented, would this cause you to revise your estimated cost of equity?

A88. 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.

Q89. Does this conclude your direct testimony?

A89. Yes, it does.

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(Winter 2013)

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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, 2007-13

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., 1985-2011
- Member Board of Directors, Oceanstone Inn & Cottages Resort 2011
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.
- Member Board of Directors, Hotel Equities, Inc., 2009-2011

PROFESSIONAL CLIENTS

AGL Resources
AT & T Communications
Alagasco - Energen
Alaska Anchorage Municipal Light & Power
Alberta Power Ltd.
Allete
AmerenUE
American Water Works Company
Ameritech
Arkansas Western Gas
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
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

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

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.

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.

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

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.

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 in a Restructured Environment
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education. faculty member 2008-2013.
  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

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Southern Bell, So. Carolina PSC, Docket #82-294C

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Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

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Georgia Power, Georgia PSC, Docket # 3270-U, 1981

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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

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Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

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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

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 2012-XXX

Duke Energy Ohio, Ohio, Case No. 11-XXXX-EL-SSO

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.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

Exhibit RAM-2 Page 1 of 2
Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth
1	Alliant Energy	4.2	6.5
2	Ameren Corp.	5.5	-1.0
3	Avista Corp.	5.0	3.5
4	Black Hills	4.2	7.0
5	CenterPoint Energy	4.2	5.0
6	CMS Energy Corp.	4.2	7.0
7	Consol. Edison	4.4	4.0
8	Dominion Resources	4.4	5.0
9	DTE Energy	4.1	5.0
10	Duke Energy	5.0	4.5
11	Exelon Corp.	7.0	-2.0
12	Integrys Energy	5.2	6.0
13	MGE Energy	3.1	5.0
14	Northeast Utilities	3.7	8.0
15	NorthWestern Corp.	4.4	3.5
16	NV Energy Inc.	3.9	11.0
17	OGE Energy	2.9	4.5
18	Pepco Holdings	5.5	7.0
19	PG&E Corp.	4.5	3.5
20	Public Serv. Enterprise	4.9	-2.0
21	SCANA Corp.	4.4	4.0
22	Sempra Energy	3.7	4.5
23	TECO Energy	5.3	5.5
24	UIL Holdings	4.8	4.0
25	UNS Energy	4.1	5.5
26	Vectren Corp.	4.9	5.5
27	Wisconsin Energy	3.6	6.5
28	Xcel Energy Inc.	4.1	6.0

30 Notes:

Column 2, 3: Value Line Investment Analyzer, 12/2012

Ameren. Exelon, and Publ Serv Ent have negative projected growth rates and are excluded

Exhibit RAM-2 Page 2 of 2
Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Company Name	Current Dividend Yield	Projected EPS Growth	% Expected Divid Yield	Cost of Equity	ROE
1	Alliant Energy	4.2	6.5	4.43	10.93	11.16
2	Avista Corp.	5.0	3.5	5.21	8.71	8.98
3	Black Hills	4.2	7.0	4.53	11.53	11.76
4	CenterPoint Energy	4.2	5.0	4.41	9.41	9.64
5	CMS Energy Corp.	4.2	7.0	4.45	11.45	11.69
6	Consol. Edison	4.4	4.0	4.58	8.58	8.82
7	Dominion Resources	4.4	5.0	4.64	9.64	9.89
8	DTE Energy	4.1	5.0	4.35	9.35	9.58
9	Duke Energy	5.0	4.5	5.17	9.67	9.95
10	Integrys Energy	5.2	6.0	5.46	11.46	11.75
11	MGE Energy	3.1	5.0	3.30	8.30	8.47
12	Northeast Utilities	3.7	8.0	4.02	12.02	12.23
13	NorthWestern Corp.	4.4	3.5	4.54	8.04	8.28
14	NV Energy Inc.	3.9	11.0	4.36	15.36	15.59
15	OGE Energy	2.9	4.5	3.01	7.51	7.67
16	Pepco Holdings	5.5	7.0	5.89	12.89	13.19
17	PG&E Corp.	4.5	3.5	4.65	8.15	8.39
18	SCANA Corp.	4.4	4.0	4.59	8.59	8.83
19	Sempra Energy	3.7	4.5	3.81	8.31	8.52
20	TECO Energy	5.3	5.5	5.56	11.06	11.35
21	UIL Holdings	4.8	4.0	5.03	9.03	9.30
22	UNS Energy	4.1	5.5	4.29	9.79	10.02
23	Vectren Corp.	4.9	5.5	5.17	10.67	10.94
24	Wisconsin Energy	3.6	6.5	3.78	10.28	10.48
25	Xcel Energy Inc.	4.1	6.0	4.36	10.36	10.59
27	AVERAGE	4.31	5.50	4.54	10.04	10.28
28	**MEDIAN**	4.23	5.00	4.53	9.67	**9.95**
29	MIDPOINT	4.19	7.25	4.45	11.44	11.63

Notes:
Column 1, 2, 3: Value Line Investment Analyzer, 12/2012
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3
Ameren, Exelon, Publ Serv Enterprise eliminated on account of negative projected growth rates.

Exhibit RAM-3 Page 1 of 2
Combination Elec & Gas Utilities
DCF Analysis Analysts' Growth Forecasts

	(1)	(2)	(3)
Line No.	Company Name	Current Dividend Yield	Analysts' Growth Forecast
1	Alliant Energy	4.2	6.1
2	Ameren Corp.	5.5	-1.4
3	Avista Corp.	5.0	4.3
4	Black Hills	4.2	6.0
5	CenterPoint Energy	4.2	5.7
6	CMS Energy Corp.	4.2	6.0
7	Consol. Edison	4.4	3.3
8	Dominion Resources	4.4	5.0
9	DTE Energy	4.1	5.0
10	Duke Energy	5.0	4.1
11	Exelon Corp.	7.0	-4.9
12	Integrys Energy	5.2	5.3
13	MGE Energy	3.1	4.0
14	Northeast Utilities	3.7	7.2
15	NorthWestern Corp.	4.4	5.3
16	NV Energy Inc.	3.9	15.1
17	OGE Energy	2.9	5.4
18	Pepco Holdings	5.5	5.4
19	PG&E Corp.	4.5	2.5
20	Public Serv. Enterprise	4.9	-2.1
21	SCANA Corp.	4.4	4.8
22	Sempra Energy	3.7	4.3
23	TECO Energy	5.3	1.8
24	UIL Holdings	4.8	4.5
25	UNS Energy	4.1	6.3
26	Vectren Corp.	4.9	5.0
27	Wisconsin Energy	3.6	5.4
28	Xcel Energy Inc.	4.1	4.9

33 Notes:

Column 1: Value Line Investment Analyzer, 12/2012
Column 2: Zacks Investment Research, 12/2012

Ameren, Exelon, Publ Serv Enterprise eliminated on account of negative growth rates.

Exhibit RAM-3 Page 2 of 2
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	4.2	6.1	4.41	10.53	10.77
2	Avista Corp.	5.0	4.3	5.25	9.58	9.85
3	Black Hills	4.2	6.0	4.48	10.48	10.72
4	CenterPoint Energy	4.2	5.7	4.44	10.16	10.39
5	CMS Energy Corp.	4.2	6.0	4.41	10.38	10.61
6	Consol. Edison	4.4	3.3	4.54	7.83	8.07
7	Dominion Resources	4.4	5.0	4.64	9.61	9.85
8	DTE Energy	4.1	5.0	4.35	9.32	9.54
9	Duke Energy	5.0	4.1	5.15	9.21	9.48
10	Integrys Energy	5.2	5.3	5.42	10.75	11.04
11	MGE Energy	3.1	4.0	3.27	7.27	7.44
12	Northeast Utilities	3.7	7.2	3.99	11.23	11.44
13	NorthWestern Corp.	4.4	5.3	4.62	9.95	10.20
14	NV Energy Inc.	3.9	15.1	4.52	19.62	19.86
15	OGE Energy	2.9	5.4	3.03	8.39	8.55
16	Pepco Holdings	5.5	5.4	5.80	11.23	11.53
17	PG&E Corp.	4.5	2.5	4.60	7.05	7.29
18	SCANA Corp.	4.4	4.8	4.62	9.39	9.63
19	Sempra Energy	3.7	4.3	3.81	8.11	8.31
20	TECO Energy	5.3	1.8	5.36	7.16	7.45
21	UIL Holdings	4.8	4.5	5.06	9.55	9.81
22	UNS Energy	4.1	6.3	4.33	10.63	10.85
23	Vectren Corp.	4.9	5.0	5.15	10.15	10.42
24	Wisconsin Energy	3.6	5.4	3.74	9.16	9.36
25	Xcel Energy Inc.	4.1	4.9	4.31	9.22	9.45
27	AVERAGE	4.31	5.31	4.53	9.84	10.08
28	**MEDIAN**	4.23	5.00	4.52	9.58	**9.85**
	MIDPOINT	4.19	8.45	4.42	13.34	13.58

Notes:
Column 1, 2: Value Line Investment Analyzer, 12/2012
Column 3: Zacks long-term earnings growth forecast, 12/2012
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

Ameren, Exelon, Publ Serv Enterprise eliminated on account of negative growth rates.

VALUE LINE WESTERN ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Avista Corp.	5.0	3.5
2	Black Hills	4.2	7.0
3	Edison Int'l	2.9	0.0
4	El Paso Electric	3.3	3.5
5	Hawaiian Elec.	5.0	9.0
6	IDACORP Inc.	3.6	2.0
7	NV Energy Inc.	3.9	11.0
8	PG&E Corp.	4.5	3.5
9	Pinnacle West Capital	4.3	5.0
10	PNM Resources	2.8	16.0
11	Portland General	4.1	5.5
12	Sempra Energy	3.7	4.5
13	UNS Energy	4.1	5.5
14	Xcel Energy Inc.	4.1	6.0

16 Notes:

Column 1, 2: Value Line Investment Analyzer, 12/2012

Edison removed on account of zero growth rate

VALUE LINE WESTERN ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Avista Corp.	5.0	3.5	5.21	8.71	8.98
2	Black Hills	4.2	7.0	4.53	11.53	11.76
3	El Paso Electric	3.3	3.5	3.42	6.92	7.10
4	Hawaiian Elec.	5.0	9.0	5.44	14.44	14.73
5	IDACORP Inc.	3.6	2.0	3.66	5.66	5.85
6	NV Energy Inc.	3.9	11.0	4.36	15.36	15.59
7	PG&E Corp.	4.5	3.5	4.65	8.15	8.39
8	Pinnacle West Capital	4.3	5.0	4.54	9.54	9.77
9	PNM Resources	2.8	16.0	3.19	19.19	19.36
10	Portland General	4.1	5.5	4.33	9.83	10.05
11	Sempra Energy	3.7	4.5	3.81	8.31	8.52
12	UNS Energy	4.1	5.5	4.29	9.79	10.02
13	Xcel Energy Inc.	4.1	6.0	4.36	10.36	10.59
15	AVERAGE	4.04	6.31	4.29	10.60	10.82
16	**MEDIAN**	4.10	5.50	4.36	9.79	**10.02**
17	MIDPOINT	3.89	9.00	4.31	12.43	12.61

19 Notes:

Column 1, 2: Value Line Investment Analyzer, 12/2012
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

Edison removed on account of zero growth rate

VALUE LINE WESTERN ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Avista Corp.	5.0	4.3
2	Black Hills	4.2	6.0
3	Edison Int'l	2.9	7.3
4	El Paso Electric	3.3	1.1
5	Hawaiian Elec.	5.0	6.4
6	IDACORP Inc.	3.6	4.0
7	NV Energy Inc.	3.9	15.1
8	PG&E Corp.	4.5	2.5
9	Pinnacle West Capital	4.3	6.0
10	PNM Resources	2.8	8.2
11	Portland General	4.1	4.1
12	Sempra Energy	3.7	4.3
13	UNS Energy	4.1	6.3
14	Xcel Energy Inc.	4.1	4.9

16 Notes:

Column 1: Value Line Investment Analyzer, 12/2012

Column 2: Zacks Investment Research, 2/2012

VALUE LINE WESTERN ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Avista Corp.	5.0	4.3	5.25	9.58	9.85
2	Black Hills	4.2	6.0	4.48	10.48	10.72
3	Edison Int'l	2.9	7.3	3.14	10.39	10.56
4	El Paso Electric	3.3	1.1	3.34	4.44	4.61
5	Hawaiian Elec.	5.0	6.4	5.31	11.66	11.94
6	IDACORP Inc.	3.6	4.0	3.73	7.73	7.93
7	NV Energy Inc.	3.9	15.1	4.52	19.62	19.86
8	PG&E Corp.	4.5	2.5	4.60	7.05	7.29
9	Pinnacle West Capital	4.3	6.0	4.58	10.61	10.85
10	PNM Resources	2.8	8.2	2.98	11.18	11.33
11	Portland General	4.1	4.1	4.27	8.35	8.57
12	Sempra Energy	3.7	4.3	3.81	8.11	8.31
13	UNS Energy	4.1	6.3	4.33	10.63	10.85
14	Xcel Energy Inc.	4.1	4.9	4.31	9.22	9.45
16	AVERAGE	3.96	5.74	4.19	9.93	10.15
17	**MEDIAN**	4.09	5.46	4.32	9.99	**10.21**
	MIDPOINT	3.89	8.10	4.14	12.03	12.24

19 Notes:

Column 1: Value Line Investment Analyzer, 12/2012
Column 2: Zacks Investment Research, 12/2012
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

Exhibit RAM-6 Page 1 of 2

Combination Elec & Gas Utilities

Line No.	(1) Company Name	(2) Beta
1	Alliant Energy	0.70
2	Ameren Corp.	0.80
3	Avista Corp.	0.70
4	Black Hills	0.80
5	CenterPoint Energy	0.75
6	CMS Energy Corp.	0.75
7	Consol. Edison	0.60
8	Dominion Resources	0.70
9	DTE Energy	0.75
10	Duke Energy	0.60
11	Exelon Corp.	0.80
12	Integrys Energy	0.90
13	MGE Energy	0.60
14	Northeast Utilities	0.70
15	NorthWestern Corp.	0.70
16	NV Energy Inc.	0.85
17	OGE Energy	0.75
18	Pepco Holdings	0.75
19	PG&E Corp.	0.50
20	Public Serv. Enterprise	0.75
21	SCANA Corp.	0.65
22	Sempra Energy	0.80
23	TECO Energy	0.85
24	UIL Holdings	0.70
25	UNS Energy	0.70
26	Vectren Corp.	0.70
27	Wisconsin Energy	0.60
28	Xcel Energy Inc.	0.60
30	**AVERAGE**	**0.72**
31	**MEDIAN**	**0.70**

Source: VLIA 12/2012

Value Line Western Electric Utilities

	(1)	(2)
Line No.	Company Name	Beta
1	Avista Corp.	0.70
2	Black Hills	0.80
3	Edison Int'l	0.75
4	El Paso Electric	0.70
5	Hawaiian Elec.	0.70
6	IDACORP Inc.	0.70
7	NV Energy Inc.	0.85
8	PG&E Corp.	0.50
9	Pinnacle West Capital	0.70
10	PNM Resources	0.90
11	Portland General	0.75
12	Sempra Energy	0.80
13	UNS Energy	0.70
14	Xcel Energy Inc.	0.60
16	**AVERAGE**	**0.73**
17	**MEDIAN**	**0.70**

Source: VLIA 12/2012

Utility Industry Historical Risk Premium

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Long-Term Government 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 Yields
1	1931	4.07%	1,000.00						
2	1932	3.15%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%	-3.69%
3	1933	3.36%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%	-25.23%
4	1934	2.93%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%	-23.34%
5	1935	2.76%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%	73.87%
6	1936	2.55%	1,032.74	32.74	27.60	6.03%	20.69%	14.66%	18.14%
7	1937	2.73%	972.40	-27.60	25.50	-0.21%	-37.04%	-36.83%	-39.77%
8	1938	2.52%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%	19.93%
9	1939	2.26%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%	9.00%
10	1940	1.94%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%	-19.09%
11	1941	2.04%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%	-33.61%
12	1942	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%	12.93%
13	1943	2.48%	996.86	-3.14	24.60	2.15%	46.07%	43.92%	43.59%
14	1944	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%	15.57%
15	1945	1.99%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%	51.34%
16	1946	2.12%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%	-0.86%
17	1947	2.43%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%	-15.59%
18	1948	2.37%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%	1.64%
19	1949	2.09%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%	29.30%
20	1950	2.24%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%	1.01%
21	1951	2.69%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%	15.94%
22	1952	2.79%	984.75	-15.25	26.90	1.17%	19.25%	18.08%	16.46%
23	1953	2.74%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%	5.11%
24	1954	2.72%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%	22.00%
25	1955	2.95%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%	8.31%
26	1956	3.45%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%	1.61%
27	1957	3.23%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%	3.13%
28	1958	3.82%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%	36.88%
29	1959	4.47%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%	3.02%
30	1960	3.80%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%	16.46%
31	1961	4.15%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%	25.18%
32	1962	3.95%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%	-6.39%
33	1963	4.17%	970.35	-29.65	39.50	0.99%	12.36%	11.37%	8.19%
34	1964	4.23%	991.96	-8.04	41.70	3.37%	15.91%	12.54%	11.68%
35	1965	4.50%	964.64	-35.36	42.30	0.69%	4.67%	3.98%	0.17%
36	1966	4.55%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%	-9.03%
37	1967	5.56%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%	-6.19%
38	1968	5.98%	951.38	-48.62	55.60	0.70%	10.32%	9.62%	4.34%
39	1969	6.87%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%	-22.29%
40	1970	6.48%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%	10.08%
41	1971	5.97%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%	-3.56%

Utility Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	(2) 20 year Maturity Bond Value	(3) Gain/Loss	(4) Interest	(5) Bond Total Return	(6) S&P Utility Index Return	(7) Utility Equity Risk Premium Over Bond Returns	(8) Utility Equity Risk Premium Over Bond Yields
42	1972	5.99%	997.69	-2.31	59.70	5.74%	8.15%	2.41%	2.16%
43	1973	7.26%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%	-25.33%
44	1974	7.60%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%	-29.15%
45	1975	8.05%	955.63	-44.37	76.00	3.16%	44.49%	41.33%	36.44%
46	1976	7.21%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%	24.60%
47	1977	8.03%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%	0.61%
48	1978	8.98%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%	-12.69%
49	1979	10.12%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%	3.46%
50	1980	11.99%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%	3.09%
51	1981	13.34%	906.45	-93.55	119.90	2.63%	11.74%	9.11%	-1.60%
52	1982	10.95%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%	15.57%
53	1983	11.97%	923.12	-76.88	109.50	3.26%	20.01%	16.75%	8.04%
54	1984	11.70%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%	14.34%
55	1985	9.56%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%	23.49%
56	1986	7.89%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%	20.64%
57	1987	9.20%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%	-12.12%
58	1988	9.18%	1,001.82	1.82	92.00	9.38%	18.27%	8.89%	9.09%
59	1989	8.16%	1,099.75	99.75	91.80	19.16%	47.80%	28.64%	39.64%
60	1990	8.44%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%	-11.01%
61	1991	7.30%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%	7.31%
62	1992	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%	0.84%
63	1993	6.54%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%	7.87%
64	1994	7.99%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%	-15.93%
65	1995	6.03%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%	36.12%
66	1996	6.73%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%	-3.59%
67	1997	6.02%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%	18.67%
68	1998	5.42%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%	9.40%
69	1999	6.82%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%	-15.67%
70	2000	5.58%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%	54.12%
71	2001	5.75%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%	-36.16%
72	2002	4.84%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%	-34.88%
73	2003	5.11%	966.42	-33.58	48.40	1.48%	26.11%	24.63%	21.00%
74	2004	4.84%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%	19.38%
75	2005	4.61%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%	12.18%
76	2006	4.91%	962.06	-37.94	46.10	0.82%	20.95%	20.13%	16.04%
77	2007	4.50%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%	14.86%
78	2008	3.03%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%	-32.02%
79	2009	4.58%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%	7.36%
80	2010	4.14%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%	1.35%
80	2011	2.48%	1,260.50	260.50	41.40	30.19%	19.88%	-10.31%	17.40%

Exhibit RAM-7

Utility Industry Historical Risk Premium

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Long-Term Government 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 Yields
80	**Mean**							**5.3%**	5.9%

Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Dec. to Dec.
Dec. Bond yields from Ibbotson Associates 2011 Valuation Yearbook Table B-9 Long-Term Government Bonds Yields

MRP Calculations Full Value Line Database
(n = 7,698 stocks)

	(1)	(2)
Dividend Yield (spot, expected)	D/P	0.45
Forecast Growth (DPS, EPS)	g	11.70
Annual DCF Return (1 + g)	K_{ann}	12.20
Quarterly DCF Return	K_{qtly}	12.40
Risk-Free Rate	R_f	4.70
DCF Market Risk Premium	DCF MRP	7.70
Ibbotson Historical Mkt Risk Premium	HIST MRP	6.60
Average Mkt Risk Premium	**AVG MRP**	**7.15**

Source: Value Line Investment Analyzer 2012

ALLOWED RISK PREMIUM
ELECTRIC UTILITY INDUSTRY

Line	Date	Treasury Bond Yield[1] (1)	Authorized Electric Returns[2] (2)	Indicated Risk Premium (3)
1	1986	7.89%	13.93%	6.0%
2	1987	9.20%	12.99%	3.8%
3	1988	9.18%	12.79%	3.6%
4	1989	8.16%	12.97%	4.8%
5	1990	8.44%	12.70%	4.3%
6	1991	7.30%	12.55%	5.3%
7	1992	7.26%	12.09%	4.8%
8	1993	6.54%	11.41%	4.9%
9	1994	7.99%	11.34%	3.4%
10	1995	6.03%	11.55%	5.5%
11	1996	6.73%	11.39%	4.7%
12	1997	6.02%	11.40%	5.4%
13	1998	5.42%	11.66%	6.2%
14	1999	6.82%	10.77%	4.0%
15	2000	5.58%	11.43%	5.9%
16	2001	5.75%	11.09%	5.3%
17	2002	4.84%	11.16%	6.3%
18	2003	5.11%	10.97%	5.9%
19	2004	4.84%	10.75%	5.9%
20	2005	4.61%	10.54%	5.9%
21	2006	4.91%	10.36%	5.5%
22	2007	4.50%	10.36%	5.9%
23	2008	3.03%	10.46%	7.4%
24	2009	4.58%	10.48%	5.9%
25	2010	4.25%	10.34%	6.1%
26	2011	3.91%	10.22%	6.3%
27	**Average**	**6.11%**	**11.45%**	**5.34%**

Sources:

[1] Morninstar 2010 Valuation Yearbook Table B-9

[2] SNL (Regulatory Research Associates), *Regulatory Focus.* Jan. 85 - Jan 12

FERC ALLOWED ROE ELECTRIC UTILITIES

Date	Docket No.	Allowed ROE	30-Yr Treas Yld	Risk Premium
Feb 2011	ER11 - 2377	10.40	4.52	5.88
May 2011	ER10 - 80	12.38	4.29	8.09
May 2011	ER11 - 13	10.09	4.29	5.80
June 2011	ER10 - 1377	10.40	4.23	6.17
June 2011	ER11 - 3352	11.18	4.23	6.95
June 2011	ER10 - 516	10.55	4.23	6.32
Oct 2011	ER11 - 2895	10.20	3.13	7.07
Oct 2011	ER11 - 4069	9.93	3.13	6.80
Nov 2011	ER08 - 386	10.40	3.02	7.38
Dec 2011	ER11 - 3352	11.18	2.98	8.20
May 2012	ER11 - 2853	10.10	2.93	7.17
May 2012	ER11 - 2853	10.40	2.93	7.47
Jun 2012	ER11 - 1593	12.38	2.70	9.68
	AVERAGE	**10.74**	**3.59**	**7.15**

APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between \$60 and \$500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9.99	13.28%	4.39%
10 - 19.99	8.72	2.76
20 - 39.99	6.93	2.42
40 - 59.99	5.87	1.32
60 - 79.99	5.18	2.34
80 - 99.99	4.73	2.16
100 - 199.99	4.22	2.31
200 - 499.99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below 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, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is 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 case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1-f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal

DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	5.00%		5.00%	5.00%	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	4.53%		4.53%	4.53%	

Exhibit No. SDG-10

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF
SANDRA K. HRNA
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY
EXHIBIT NO. SDG-10

#274419

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

I. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Sandra K. Hrna. My business address is 8330 Century Park Court, San Diego, CA 92123.

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

A2. I am employed by San Diego Gas & Electric Company (SDG&E or Company), as the Assistant Treasurer and Director of Financial Analysis & Regulatory Accounts.

Q3. What are your duties and responsibilities?

A3. My current responsibilities include oversight of the development, analysis and implementation of financing strategies, revenue requirements, regulatory accounts, and cost recovery mechanisms for SDG&E.

Q4. Please describe your educational background.

A4. I have a Bachelors of Business Administration – Accounting and a Masters in Professional Accounting – Tax from The University of Texas at Austin. I received both in 1991 in a joint degree program.

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

A5. I have been employed by SDG&E and Sempra Energy since 2001. In addition to my current position, I have held various Accounting and Finance positions within the organization, including Director of Compliance & Accounts Payable and Director of Business Planning, Budgets & Claims.

Q6. Have you previously testified before the Federal Energy Regulatory Commission (FERC)?

A6. No, I have not.

II. PURPOSE

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to provide an overview of the investment risk faced by SDG&E 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's testimony witnesses James P. Avery and Dr. Roger A. Morin.

I will explain SDG&E's risk profile in the following areas:

- Business Risk,
- Financial Risk, and
- Regulatory Risk.

Q8. Please summarize the key elements of your testimony.

A8. I will explain SDG&E's investment risk profile in the following sections:

I. Introduction
II. Purpose of testimony
III. Risk Overview
IV. Business Risk
V. Financial Risk
VI. Regulatory Risk
VII. Summary

III. RISK OVERVIEW

Q9. Why is risk an important component of assessing SDG&E's return on common equity?

A9. Capital markets determine the price of investor capital (*i.e.*, the required return on stocks and bonds) based upon 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.

IV. BUSINESS RISK

Q10. Please describe business risk.

A10. 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. DBRS, a North American credit rating agency, explains that "[d]iffering business risk profiles impact the assessment of a company's financial risk profile, and thus, it is important to understand the extraneous influences and business factors a company is or could be affected by despite its financial strength."[1]

Policy initiatives and changing customer behaviors are affecting the energy industry in California and changing the way in which SDG&E provides reliable and safe energy services to its customers. This changing environment presents inherent business risks, including the need for a major capital spending program, uncertainty regarding energy supplies and transmission and distribution system operations, and implementation and ongoing management of new technologies. Collectively, these initiatives amplify the importance of regulatory consistency and maintenance of a strong financial balance sheet to preserve the creditworthiness of SDG&E.

Q11. What are the business risks that SDG&E faces and how does it pertain to Transmission activities?

A11. SDG&E faces a number of significant business risks associated with the provision of gas and electric service in the current and future periods, including:

- Elevated level of capital investment;
- Litigation and insurance risks related to catastrophic events that are innate to Southern California
- Unprecedented changes in the energy industry.

Each component will be described separately in my testimony.

A. Elevated Level of Capital Investment

Q12. Describe the risk associated with elevated level of capital investment.

[1] "Methodology Rating North American Energy Utilities (Electric, Natural Gas, and Pipelines)", June 2010, at p. 2.

A12. Over the next five years, SDG&E plans to invest approximately $5.8 billion in capital projects, of which approximately $2 billion is specific to Transmission projects. As a result of the robust capital program, SDG&E has accessed the capital markets in recent years at much higher levels than in previous years to finance the large capital investments. For example, from 2007 through 2009, SDG&E spent on average approximately $750 million per year for new capital investments. During the most recent three-year span, 2010 through 2012, SDG&E has spent, on average, over $1.5 billion per year for new capital investments, which is more than double the preceding three year rate of spending. Consequently, the need to access additional incremental capital beyond the current high levels will be even more challenging given the significant risks that I and other SDG&E witnesses discuss. SDG&E must continue to compete for new capital funding, not only with other utilities but also with the growing investments in global markets. In relationship to our peers, our significantly ramped-up capital expenditure program brings with it additional investment risks driven by a lower amount of free cash flow relative to our capitalization during this capital ramp-up period.

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. Moody's Investor's Service ("Moody's"), for example, recognized the risks associated with SDG&E's capital investment plan in its June 30, 2011 rating of the Company. In its report, Moody's noted that SDG&E's credit metrics are expected to weaken due to the size of its capital expenditure program. 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. FERC support for SDG&E's financial integrity and flexibility will be critical in order to attract the capital needed to fund these projects on reasonable terms and costs to customers. To ensure that SDG&E has ready access to capital funding at a reasonable cost, SDG&E requires a just and reasonable ROE. The proposed ROE will provide the cash flow necessary to sustain strong credit metrics appealing to both investors and rating agencies.

B. Litigation and Insurance Risks related to catastrophic events that are innate to Southern California.

With the third highest number of civil cases in the United States, California is one of the most litigious regions in the country.[2] Higher litigation risks can result in increased legal and defense costs for SDG&E. Moreover, the business risk posed by California's generally high rate of litigation is greatly exacerbated by California's interpretation of the "inverse condemnation" doctrine and its application to investor-owned utilities. California courts have held that an investor-owned utility may be held strictly liable under the "inverse condemnation" doctrine for damage to private property when the source is a utility facility.[3] Under this doctrine, even if a utility is in full compliance with relevant safety regulations and/or there is no proof of negligence, if utility equipment or facilities are involved in an incident, for example, the utility may be held liable for resulting damages, even where the damage results from third party negligence or actions. In addition, successful inverse condemnation plaintiffs are entitled to attorneys' fees and pre-judgment interest, which not only add to the total litigation cost, but also encourage plaintiffs to sue under this theory.

As a regulated utility required to provide electric and natural gas distribution services to all customers residing in its service territory, SDG&E faces inherent operational risk. Insurance carriers' negative perceptions of California's inverse condemnation doctrine, particularly in connection with the recent history of large wildfire claims against California utilities, have contributed to a reduction in available liability insurance and a significant increase in price over the past few years. The current difficulty in obtaining adequate liability insurance coverage creates investor concerns regarding under-insurance or, potentially, an inability by SDG&E to obtain third party liability insurance at all.

[2] Based on data (through 2009) compiled by the Court Statistics Project: http://www.courtstatistics.org/. The Court Statistics Project is a component of the Bureau of Justice Statistics, the statistical arm of the Office of Justice Programs in the U.S. Department of Justice. *See* http://bjs.ojp.usdoj.gov/index.cfm?ty=dcdetail&iid=283.

[3] *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.")

While SDG&E has sought to secure all of the liability insurance coverage reasonably available in the global insurance markets,[4] it is potentially underinsured compared to the risk it must undertake in order to provide utility service to all of its customers. For example, SDG&E had over $1 billion in liability insurance coverage before the 2007 wildfires, but is facing claims of over $2 billion related to the wildfires. Thus, the approximately $1 billion in wildfire liability coverage and $822.5 million in general (non-wildfire) liability coverage SDG&E has in place today could be inadequate to cover another large wildfire or other major non-wildfire incidents.[5] Moreover, the fact that insurance is available now is no guarantee that insurance will continue to be available in the future. As SDG&E's post-wildfire insurance procurement has demonstrated, the insurance market is unstable and insurance availability can change quickly. The risk that SDG&E is potentially one wildfire or other major incident away from being uninsured is an obvious concern.

In sum, California's generally high rate of litigation, coupled with its unfavorable interpretation of the inverse condemnation doctrine, presents a significant business risk. This is particularly true when doing business as an electric utility providing service in the tinderbox southwestern U.S. where dry conditions, high winds and close proximity to densely populated areas have historically led to catastrophic wildfires. California is generally viewed as having a "constructive regulatory environment" with a low perceived likelihood of credit-adverse behavior. While this provides a degree of comfort to the investment community that the California Public Utility Commission (CPUC) will continue to act in a manner that supports recovery of reasonable costs,[6] the possibility of uninsured liability in the event of a significant wildfire event or other major incident is, nevertheless, a serious cause for investor concern.

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[4] *See* SDG&E Advice Letter 2285-E filed September 9, 2011; *see also* D.10-12-053, *mimeo*, p. 32 ("In an effort to establish sound public policy, we agree that SDG&E's decision to obtain all the liability insurance that was reasonably available in the world insurance market was a prudent risk mitigation strategy.")

[5] *See id.* at pp. 3-4.

[6] SDG&E notes that it has requested a defined mechanism for recovery of uninsured wildfire-related liability in CPUC Application 09-08-020. The mechanism, as proposed, would not cover uninsured liability for non-wildfire events.

C. Unprecedented Changes in the Energy Industry

Q13. Describe the risk associated with unprecedented changes in the energy industry.

A13. While California has a tradition of public policy initiatives that embrace new technologies, the number of new technologies and programs being simultaneously implemented in the current period is without historical precedent. Specific areas of change include technological infrastructure and cyber security; distributed generation and electric vehicles; and renewable energy. 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, and is likely to impact SDG&E's earnings. 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.

1. Technology and cyber security

Q14. Describe the business risk associated with technology and cyber security.

A14. SDG&E earned the title "The Nation's Most Intelligent Utility" for the third year in a row in 2012, in recognition of SDG&E's leadership role in the revolutionary deployment of the Smart Grid program.[7] Smart Meters are one component of the Smart Grid infrastructure. With an increasing number of cyber assets dispersed over a broader geographic area, controlling more parts of the grid and communicating more data than ever before, the threat of a cyber security breach increases. Deployment of these new business technologies represents a new and large-scale opportunity for attacks on the information systems and integrity of the energy grid. These attacks could have a material adverse effect on the business, financial conditions, and operations of the company.

The North American Electric Reliability Corporation (NERC) and the Department of Energy (DOE) have noted that "on the high-impact end of the scale are highly-coordinated, well-planned attacks against multiple assets designed to disable the

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[7] Kathleen W. Davis, *San Diego Gas & Electric No. 2 Utility Racks Up Three Consecutive Wins*, INTELLIGENT UTILITY MAGAZINE, March / April 2012, http://www.intelligentutility.com/magazine/article/261485/san-diego-gas-electric.

system."[8] According to the Center for Strategic & International Studies in Washington, D.C., "if there was a cyber attack, the electrical grid would be target number one" for terrorists.[9] As SDG&E evolves from a "traditional" electric and gas utility into a utility of the future through deployment of new Smart Grid technologies, investors' view on SDG&E business risk profile will also change. A modern utility with significant technology risk will require a just and reasonable ROE that reflects SDG&E's increased risks to compensate for these factors.

2. Increase in distributed generation and plug-in electric vehicles

Q15. Describe the business risk associated with distributed generation and plug-in electric vehicles.

A15. The high adoption rate of rooftop solar[10] and plug-in electric vehicles (PEVs)[11] 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 its customers are early adopters of these newer 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.

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[8] *High-Impact, Low-Frequency Event Risks to the North American Bulk Power System*, NERC-DOE, June 2010, p.26. http://www.nerc.com/files/HILF.pdf

[9] Brian Wingfield, Power-Grid Cyber Attack Seen Leaving Millions in Dark for Months, BLOOMBERG, January 31, 2012. http://www.bloomberg.com/news/2012-02-01/cyber-attack-on-u-s-power-grid-seen-leaving-millions-in-dark-for-months.html.

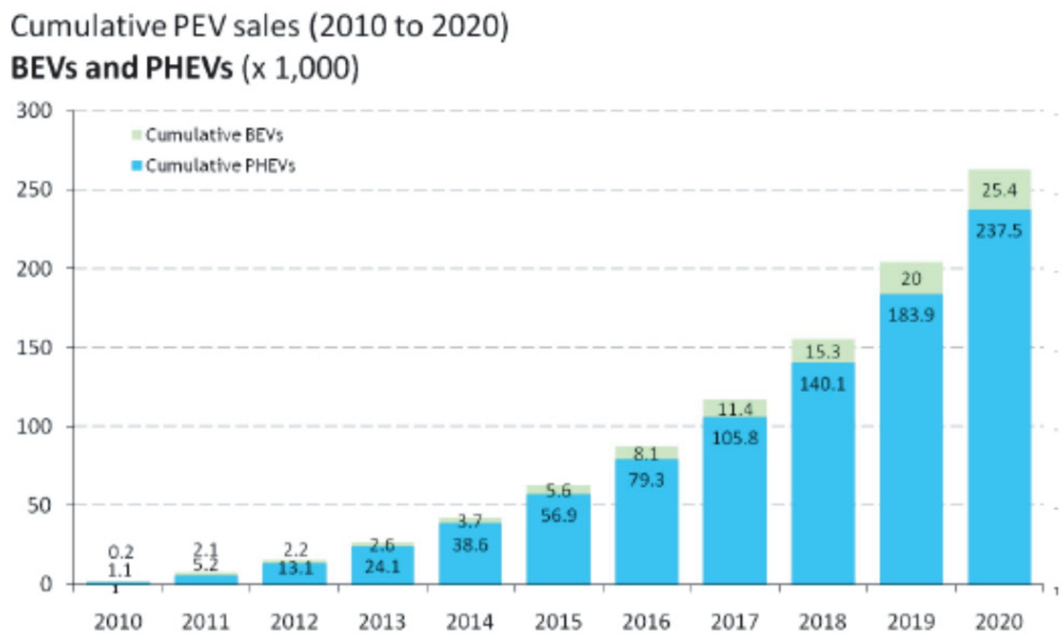
[10] In a January, 2012 report by the Environment California Research & Policy Center, the city of San Diego was named "America's solar city" for having the most solar rooftop installations and solar capacity installed in the United States. As of August 2011, there were 4,507 solar rooftop installations for a total solar rooftop capacity of 37 MW in the city of San Diego, beating out larger cities such as Los Angeles and San Jose. *California's Solar Cities 2012: Leaders in the Race Toward a Clean Energy Future,* Environment California Research & Policy Center, January 24, 2012, http://www.environmentcalifornia.org/sites/environment/files/reports/California%27s%20Solar%20Cities%202012%20-%20Final.pdf

[11] The California Center for Sustainable Energy reported that in 2010-2011, 20% of the state's Clean Vehicle Rebate was issued in San Diego County. *Clean Vehicle Rebate Project: Fiscal Year 2009-2011 Final Report*, October 18, 2011, p. 7. http://www.arb.ca.gov/msprog/aqip/cvrp/CVRP_FinalReport_FY09-11.pdf.

In March 2012 Governor Brown issued an Executive Order calling for 1 million electric vehicles in CA by 2020 and 1.5 million by 2025, to accelerate the market for zero-emission vehicles in the state[12]. The shift to electric vehicles within SDG&E's service territory is real, as evidenced by SDG&E's selection to host a number of public and private programs promoting PEVs.[13] As shown in Figure 1 below, SDG&E forecasts the PEV population growing significantly – from 26,700 in 2013 to 262,900 in 2020.

Figure 1

Assessment of SDG&E Electric Vehicle Market Population



PEV is further categorized as Battery Electric Vehicles (BEVs) such as the Nissan Leaf, and Plug-in Hybrids Electric Vehicles (PHEVs) such as the Chevy Volt

The demand from PEVs on SDG&E's electric system could be enormous. Electric vehicles such as the Nissan Leaf draw 3.3 kilowatts of demand, but future

[12] Governor's Interagency Working Group on Zero-emission Vehicles, 2013 ZEV Action Plan, Feb 2013, _http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf; For the purposes of this order, zero-emission vehicles include plug-in electric vehicles.

[13] Including Daimler's Car2Go PEV car sharing pilot, the ECOTality network of approximately 1,500 public charging units, and more than 1,000 free, home-charging units going to Nissan Leaf and Chevrolet Volt buyers who qualified for a federally-funded study on consumer charging behavior.

releases (the 2012 or 2013 model year) could increase to 6.6 kilowatts,[14] exceeding the 5 to 5.5 kilowatts of demand of a typical San Diego home with central air conditioning. 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 ("O&M") costs due to the potential for reduced life expectancy on existing equipment due the impact of PEV penetration and the highly unpredictable future introduces variability to SDG&E's earnings.

3. Renewable Energy

Q16. Describe the impact of renewable energy.

A16. The passage of the new Renewables Portfolio Standard ("RPS") for California under Senate Bill X1 2 and signed by Governor Edmund G. Brown, Jr. in April 2011 increased the goal for renewable resources to 33 percent and paved the way for dramatic growth in renewable energy generation. California's comparatively ambitious RPS goals fuel investor perception that the California utilities are exposed to greater risk than utilities located in other states. This investor perception of risk is solidified with headline news such as the Solyndra bankruptcy or the delay in renewable projects due to environmental concerns.[15] SDG&E relies primarily on power purchase agreements ("PPAs") with third-party developers to meet RPS procurement requirements. Delays in renewable projects coming online can have a detrimental financial impact on the Company due to California's penalty structure for non-compliance with RPS mandates. In the event a renewable project fails, it can be extremely difficult to source in-state replacement projects that are highly viable in a timely manner.

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[14] *Nissan Updates Leaf for 2012, 2013*, Auto Trader.com, http://www.autotrader.com/research/article/car-news/110309/nissan-updates-leaf-for-2012-2013.jsp.

[15] Calico Solar Project in the Pisgah Valley of the Mojave Desert was sued by the National Resources Defense Council claiming that the project would harm endangered species. *See Environment Group Sues U.S.. Over Mojave Solar Project*, BLOOMBERG, April 2, 2012, http://www.bloomberg.com/news/2012-04-02/environment-group-sues-u-s-over-mojave-solar-project.html.

See also Problems Cast Shadow of Doubt on Solar Project, LOS ANGELES TIMES, Feb. 11, 2012, Genesis Solar Energy Project located near Blythe, CA that could be delayed or even cancelled following a deadly outbreak of distemper among kit foxes and the discovery of a prehistoric human settlement on the work site.

General challenges facing the renewable industry that could ultimately impact SDG&E include:

- Potential that the production tax credit would not be extended past 2013 or would be curtailed as a result of deficit reduction efforts at the federal level;
- Difficulty experienced by renewable energy project developers in obtaining project financing and completing the permitting process, particularly the environmental review many such projects must undergo;
- Transmission interconnection challenges;
- Successful development and implementation of renewable energy technologies and
- Timely regulatory approval of contracted renewable energy projects.

Government subsidies and loan guarantee programs play a critical role in encouraging investments in the renewable market segment given the high-risk nature of the industry. Recent legislation provides only a limited extension for Production Tax Credit ("PTC") and as a result, may further reduce investors' interest in renewable energy projects. According to the American Wind Energy Association, the last time the PTC was allowed to expire, the end of 2003, U.S. annual wind installation in 2004 declined by 76% from the previous year.[16]

In addition, the high profile bankruptcy of Solyndra and several other recipients[17] of the DOE loan guarantee program have put the DOE on the defensive, resulting in higher scrutiny of the loan program by legislators, which could lead to reduced funding for renewable projects. SDG&E's compliance with RPS program mandates is dependent on renewable energy developers' ability to bring plants online in a timely manner. Circumstances that hinder renewable energy development result in a greater level of business risk for SDG&E.

V. FINANCIAL RISK

Q17. Please describe financial risk.

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[16] Sally Bakewell, *U.S. Government Arranged Most Loans for Clean Energy in 2011*. BLOOOMBERG, Jan. 17, 2012, http://www.businessweek.com/news/2012-01-17/u-s-government-arranged-most-loans-for-clean-energy-in-2011.html.

[17] Other recipients of the DOE loan guarantee program that filed for bankruptcy include Abound Solar, Ener1 and Beacon Power.

A17. As described by Dr. Morin (RAM at 50), 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, generally speaking, companies that issue more debt instruments have higher financial risk than companies 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. SDG&E manages a capital structure of 45.25% long-term debt, 2.75% preferred stock equity, and 52% common stock equity, as recently authorized by the CPUC[18].

SDG&E has recently entered into substantial and increasing amounts of long-term PPAs; consequently, its credit ratios are likely to be negatively impacted due to the credit rating agencies' treatment of PPAs as debt equivalence.[19] SDG&E's debt equivalence for PPAs is expected to increase from $182 million (in 2011) to approximately $1.7 billion during 2013 through 2015. With such high levels of debt equivalence, 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)[20] consolidation of certain PPAs into SDG&E's balance sheet would further deteriorate SDG&E's financial credit ratios.

Absent compensation in SDG&E's authorized ROE, SDG&E's credit profile could be impacted as the Company takes on more debt for its large capital program, as well as when it takes on debt in the form of ASC 810 consolidations and imputed debt equivalences by credit rating agencies.

SDG&E's debt equivalence should be considered along with its other risks in arriving at a just and reasonable ROE. Therefore, it is important to obtain an adequate

[18] CPUC Decision 12-12-034, Ordering Paragraph #2, December 20, 2012. *Available at* 2012 Cal. PUC LEXIS 593.

[19] Debt equivalence is a concept used by credit rating agencies to describe the fixed financial obligations resulting from long term PPAs.

[20] ASC 810 adopted January 1, 2010 amended the Financial Accounting Standards Board ("FASB") issued FASB Interpretation Number ("FIN") 46(R), Consolidation of Variable Interest Entities ("VIEs"), an Interpretation of Accounting Research Bulletin No. 51, which provided guidance on the identification of and financial reporting for entities over which control is achieved through means other than voting rights. ASC 810 requires that the "primary beneficiary" of a VIEs activities consolidate the financial statements of the VIE when filing annual and quarterly reports with the Security and Exchange Commission ("SEC").

ROE in part to mitigate the effect of debt equivalence and ASC 810 consolidations, and to help preserve SDG&E's financial soundness and investment-grade credit ratings. This will allow SDG&E to continue to attract capital funding at a reasonable cost. It should be noted that SDG&E's actual overall cost of long-term debt financing has decreased significantly from 5.62% in 2008 to 5% in 2013. The lower cost of debt, when applied to SDG&E's debt portfolio of $3.8 billion, translates into material savings that continue to benefit the customer over the long term. The significant drop in costs is attributed to two major factors: a historic drop in market interest rates and SDG&E's strong credit profile, a result of prudent and proactive business/financial risk management. SDG&E's strong credit ratings allowed for significantly lower, in some cases record-breaking low debt financing costs. Consequently, SDG&E's overall long-term cost of borrowing is 49 basis points lower than SCE's and 52 basis points lower than PG&E's (the two other major California investor owned utilities). For SDG&E, this drop in costs results in annual savings over $14 million (after-tax) - a significant and recurring cost reduction that is passed onto customers. A competitive FERC ROE will continue to allow SDG&E to prudently manage and maintain its credit profile for the benefit of customers during a period of capital investment expansion.

VI. REGULATORY RISK

Q18. Please describe regulatory risk.

A18. Regulatory risk refers to new risks that investors may face from future regulatory actions.[21] In their analysis of utility debt and assessment of utility creditworthiness, credit rating agencies and investors place considerable emphasis on the regulatory environment in which companies operate. S&P, for example, notes that:

> The utility business is unique, in that in no other industry (with the possible exception of government finance) do legislative and regulatory pronouncements so significantly inform rating agency opinions. Indeed, Standard & Poor's views the regulatory and political environment in which a utility operates as one of the most significant factors in assessing the creditworthiness of regulated utilities.[22]

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[21] D.07-12-049, *mimeo*, p. 31.

[22] Standard & Poor's Ratings Direct *Influence Of Regulatory And Policy Decisions On Utility Credit Quality Deepens, Demanding Timely Assessments From Standard & Poor's*, May 15, 2007, at p.1.

The regulatory risk analysis typically focuses on three areas: (i) authorized ROE; (ii) cost recovery; and (iii) regulatory lag. Each of these three factors is addressed below.

1. Authorized ROE

A key determinant of a supportive regulatory climate is an authorized ROE that provides adequate compensation for the risk that investors must assume.[23] Hence, the regulatory risk faced by SDG&E is primarily a function of FERC's propensity to authorize an ROE that provides a just and reasonable compensation for investor risk. When FERC authorizes an ROE that is competitive, SDG&E's financial integrity remains intact and its ability to raise capital at reasonable costs is preserved, which in turn can reduce costs to the ratepayers in the long run.

The Edison Electric Institute (EEI) noted in February 2009 that history suggests that the current heightened risk levels in the financial markets will bring even greater scrutiny from the credit rating agencies with regard to regulatory supportiveness, to ensure that utilities' financial strength is maintained.[24] Therefore, it is imperative that SDG&E gets approval of its recommended ROE. Lower authorized ROEs can impair utilities' credit profile and increase the cost of capital. Fitch explains:

> Lower authorized ROEs constrain profitability and limit financing flexibility, making the utilities more reliant on external financing sources and vulnerable to higher interest rates. Weak internal cash generation, higher interests costs, and weaker interest coverage measures can lead to lower credit ratings and poor market performance for utility debt.[25]

Investors pay close attention to a utility's regulatory environment when assessing investment opportunities. For instance, in an article regarding analysts' reaction to the January 2008 recommended decision by a New York administrative law judge to reduce Consolidated Edison's ROE to 9.10 percent, SNL Interactive commented:

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[23] S&P's evaluation of regulation focuses on the ability of regulation to provide utilities with the opportunity to generate cash flow and earnings quality and stability adequate to meet investment needs, service debt and maintain a satisfactory rating profile, and generate a competitive rate of return to investors. *See* Standard & Poor's Ratings Direct, *Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry*, November 28, 2008, at p.5.

[24] Julie Cannell, *The Financial Crisis and Its Impact on the Electric Utility Industry*, Edison Electric Institute, Feb. 2009, at p.10.

[25] Fitch Ratings Ltd., *Fitch Evaluated Utility ROE Trends* U.S. Utilities, Power, and Gas Special Report, Aug. 17, 2011, at p. 3.

Regulation in New York continues to be troublesome with allowed ROEs well below national levels as a relatively new commission fails to strike a reasonable balance between ratepayer and shareholder interests . . . Returns on equity nationally have averaged about 10.5% to 11.5%, but returns in New York have been comparatively weak . . . The new commission appears to lack appreciation for the importance of access to capital (particularly in a deteriorating capital markets environment).[26]

Following the New York Public Service Commission's decision in that case, Fitch Ratings downgraded Consolidated Edison, determining that:

The outcome of yesterday's rate decision by the New York Public Service Commission (NYPSC) will not produce cash flow credit measures consistent with the prior credit ratings . . . The authorized return on equity of 9.1% is below the average for utilities of comparable risk, and in Fitch's view is inconsistent with the heavy investment program and capital raising needs facing the utility.[27]

As noted above, California utilities have generally been perceived as having a constructive regulatory environment. However, this positive view of SDG&E's regulatory environment is dependent upon FERC's adherence to its past practice of authorizing an ROE for SDG&E that is adequate given its risk.

2. Cost Recovery

Potential disallowance of operating expenses is a regulatory risk. Moody's, similarly, recognized the risks associated with the ability to recover costs in its June 30, 2011 rating of SDG&E:

Moody's believes that numerous challenges exist for electric utilities operating in the state. Among these challenges is the number of policy programs being introduced which will result in higher electric rates for all classes of customers. These programs, which result in rate base growth for SDGE and other California utilities, largely depends upon California regulators continuing to remain focused on clean energy expansion and incentivizing energy efficiency gains. However, the cost challenges are exacerbated by the current weak economy throughout the company's service territory, which may at some point impact SDGE and the other

[26] SNL Interactive, *Friday's Energy Stocks: Wall Street Tumbles; Analyst Warns about Con Edison Rate Case*, March 14, 2008. (Citing KeyBanc Capital Markets).

[27] Fitch Ratings, *Fitch Downgrades Con Ed of NY & Con Ed Inc. to 'A' on Rate Decision; On Watch Negative*, March 20, 2008.

> California utilities' ability to recover costs and earn an appropriate return on prudent investments.[28]

An example of cost recovery risk can be seen in PG&E's 2011 General Rate Case ("GRC"), where the CPUC lowered the allowed cost of capital on meters already funded by company investment, but removed from service to make way for the deployment of Smart Meters.[29] The proposal to replace the existing electro-mechanical, or "legacy" meters was made pursuant to a CPUC instituted Rulemaking (R.) 02-06-001 to initiate the advanced metering proposals.

SDG&E now faces proposals from interveners in its own pending GRC that are even more punitive. Interveners recommend, for example, disallowance of the recovery of <u>any</u> costs of capital (a zero percent rate of return) on SDG&E's replaced legacy meters, which involved significant capital investment. SDG&E has a CPUC-approved settlement agreement dictating the terms of its Smart Meter program that explicitly provides for cost recovery for legacy meters, including the cost of capital.[30] In the event the CPUC authorizes these intervener proposals, basically re-litigating past decisions and disrupting company and investor expectations regarding stranded cost recovery, it will have a negative impact on SDG&E's perceived regulatory risk.

3. Regulatory Lag

Another desirable regulatory attribute is timely decision-making. Fitch explains that regulatory lag is likely to take on added prominence in the present environment, as time (delays, protracted cases) means money (more required).[31] Likewise, S&P notes:

> So in general, a ruling that enhances a utility's ability to recover costs in a timely manner will positively affect its overall credit quality. A decision that impedes timely cost recovery will usually have a negative impact on

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[28] Moody's Investors Service, Global Credit Research, Credit Opinion: San Diego Gas & Electric., June 30, 2011, p.2.

[29] *See* D.11-05-018, *mimeo*, Conclusion of Law 45. The return on equity was lowered from 11.35 percent to 6.55 percent.

[30] *See* D.07-04-043, pp. 2, 8 and 86 – 87, as well as Appendix A, p. 2. Also see Exhibit 22 of A.05-03-15, Chapter 2, "AMI Business Vision, Policy and Methodology," July 14, 2006 Amendment, Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of Edward Fong, p. EF-26, lines 18-24.

[31] Fitch Ratings, *Fitch Evaluated Utility ROE Trends*, August 17, 2011, at p.11; *see also* Donald Murry, Michael Knapp and Zhen Zhu, *Allowed ROEs During Economic Crisis Often Fail The Equal Return For Equivalent Risk Standard*, International Association for Energy Economics, Second Quarter 2011, at p.28.

> overall credit quality. As commentators on creditworthiness, we have an obligation to make either situation clear to market participants.[32]

Recent increases and overlaps of major proceedings have forced the Company to wait to make important business decisions. Regulatory lag would further add to SDG&E regulatory risk profile and the perceived riskiness of the California regulatory market as a whole.

VII. SUMMARY

Q19. Summarize your assessment of SDG&E's overall risk.

A19. This testimony highlights the heightened business, financial and regulatory risks experienced by SDG&E in the current environment. The business risks faced by SDG&E are primarily (i) the growth in capital programs; (ii) litigation and insurance risks; and (iii) unprecedented transformation within the energy industry. Additionally, the high levels of debt equivalence are increasing SDG&E's financial risk. While SDG&E is perceived to operate in a supportive regulatory environment, it is experiencing increasing regulatory risk. For the reasons described in my testimony, SDG&E is perceived to be generally in the upper range of riskiness by investors as noted by Dr. Morin's higher beta than peers (RAM-6 at 1 and 2). These considerations are taken into account in SDG&E's overall ROE recommendation of 11.3%.

Q20. Does this conclude your testimony?

A20. Yes, it does.

[32] Standard & Poor's Ratings Direct, *Influence of Regulatory And Policy Decisions On Utility Credit Quality Deepens, Demanding Timely Assessments From Standard & Poor's*, May 15, 2007, at p.1.

VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

Sandra Hrna, being duly sworn, on oath, says that she is the Sandra Hrna identified in the foregoing prepared direct testimony; that she prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers would, under oath, be the same.

Sandra Hrna
Sandra Hrna

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 7th day of February, 2013 before me, ANNIE VICTORIA RUIZ, a Notary Public, personally appeared Sandra Hrna, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that she executed the same in her authorized capacity, and that by her signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Annie Victoria Ruiz

ANNIE VICTORIA RUIZ
COMM. #1877490
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jan 18, 2014