SABER PARTNERS, LLC

Direct Testimony of

Hyman Schoenblum, Senior Advisor

Saber Partners, LLC

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DIRECT TESTIMONY OF HYMAN SCHOENBLUM, CPUC R.17-06-026

Q. Please state your name and business address.

A. Hyman Schoenblum, Saber Partners, LLC, 44 Wall Street, New York, NY 10005

Q. What is your position with Saber Partners LLC?

A. I am a Senior Advisor to Saber Partners, LLC (Saber Partners or Saber).

Q. Please describe your educational background and professional experience.

A. I have an undergraduate BBA degree in Accounting from Baruch College in New York City and a Master's Degree in Finance from the same school.

I worked for 35 years at the Consolidated Edison Company of New York, Inc. (Con Ed), in various capacities. Con Ed is the largest electric utility in the State of New York.

At various times, I served as Con Ed's Vice President and Treasurer; Vice President and Controller; Vice President of Strategic Planning; and Chief Financial Officer of Con Ed's wholly-owned subsidiary, Orange and Rockland Utilities. I also led a task force to prepare Con Ed for the financial impacts of competition in New York State. While in those positions, I also served as a key spokesperson in Con Ed's investor relations effort.

For many years, I was a senior financial officer at Con Ed, with expertise in financial matters as well as ratemaking policies and practices of regulated utilities. I participated in the review of a variety of financial transactions; the analyses of ratemaking policies and proposals; the evaluation of the timing and method of financing decisions; the litigation of rate cases; and the assessment of capital investment determinations.

I was also involved in M&A activity at Con Ed, including evaluating merger opportunities and potential investments in competitive businesses. Decision making at Con Ed in these matters rested with the parent company's Chief Financial Officer (CFO) and Chief Executive Officer (CEO).

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After retiring from Con Ed in 2006, I joined the Maimonides Medical Center of Brooklyn, New York, as their Vice President of Internal Audit. I recently retired after close to 12 years at the hospital.

Q. What role did you play regarding investor relations with institutional and other investors for Con Ed?

A. While serving in the above-mentioned positions, I played an important role in Con Ed's relationship with the Wall Street community. Along with others, I met very frequently with institutional investors, fund managers, stock and bond research analysts and the media to present Con Ed's financial position to the investment community. When adverse financial events took place, or when rate cases were being litigated and decided, I was often on the phone with investors for many hours describing the financial implications.

Q. Have you had a role in Saber's previous activities regarding Securitization?

A. Yes. In 2015, I provided direct testimony to the Florida Public Service Commission (FPSC) on the Duke Energy Florida (DEF) $1.3 billion securitization which refinanced the unrecovered cost of a retired nuclear power plant. I testified on a number of issues including the need for close Commission oversight after the issuance of a financing order and the benefits of a "Bond Team", which included an outside financial advisor to the Commission and its staff. I also participated in all aspects of negotiations between the parties, including the FPSC staff, and the interactions between the Bond Team and the investment bankers hired to manage the issuance of the Nuclear Asset-Recovery bonds.

I also had a similar role in an earlier issuance of securitized debt in Florida for the recovery of Storm Costs.

Q. Whom do you represent in this proceeding?

A. I represent Saber Partners, LLC that has been hired by the California Community Choice Association to provide an independent evaluation and opinion as to the benefits, costs, risks and rewards for PCG and EIX, its customers and its shareholders, of using securitization as part of the

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California Commission's Rulemaking 17-06-026, to "consider alternatives to the Power Charge Indifference Adjustment".

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

A. I will analyze securitization based upon my 35 years as a senior financial executive of one of the largest electric utilities in the country. My analysis will also be based upon years of experience interacting with investment bankers, large utility investors, Wall Street analysts representing both equity and debt investors, the staff of the New York Public Service Commission and a variety of rate case intervenors. As such, I will review the potential impact on PCG and EIX of the proposed use of securitization as a financing tool to benefit their respective electric utility subsidiaries, Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE).

Q. Have you reviewed how utilities around the country have used securitizations?

A. Yes. As described in greater detail in the testimony of my colleagues Mr. Joseph Fichera and Mr. Paul Sutherland, securitized debt has been issued or authorized for investor-owned electric utilities for a wide variety of reasons, such as:

1. Recovery of remaining costs of retired power plants;
2. Recovery of stranded costs resulting from electric industry deregulation;
3. Mitigating rate increases for residential and small commercial customers;
4. Storm recovery costs and above-market power supply costs;
5. Costs of new pollution control equipment or renewable distributed generation;
6. Costs of buyouts or buydowns of high priced power purchase agreements (PPAs);
7. Refinancing a variety of regulatory assets.

Q. Why have utilities proposed securitization in the past?

A. There are four primary reasons for using securitization by electric utilities:

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1. Utilities seeking to recover operating costs incurred in the past for which future rate relief would be required, otherwise resulting in sharp rate increases for consumers (e.g., storm damages, deferred debit balances);
2. Recovery of costs for electric supply service which are higher than the market (e.g., California in 1996);
3. Utilities faced with past investments which are no longer "used and useful" but may still be reflected in current rates (e.g., stranded costs);
4. Increased expenditures for new technologies or plant and equipment additions requiring rate increases (e.g., pollution control equipment).

Q. To the best of your knowledge, has past securitization been utilized to refinance existing operating plant, which continues to be "used and useful" for utility service?

A. No, though it has been used to finance the construction of pollution control generation equipment before it was placed into service. The State of Idaho did approve legislation for securitization to be used for any corporate purpose, but no bonds have been issued under that statute.

Q. Why do you think the use of securitization has not been used for existing generation?

A. If a utility refinanced the equity invested in existing plant through securitization, it would remove the associated plant from the utility's "rate base," resulting in a concomitant rate reduction which could potentially affect earnings in a negative manner. This would conflict with generally accepted ratemaking principles, especially if the intent of the securitization was solely to reduce customer rates at the expense of shareholders.

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Q. What are the "generally accepted ratemaking principles" that you refer to above?

A. These are ratemaking principles which allow the utility to recover its prudently incurred costs of service, including capital costs, in the period when these costs were incurred (or in the case of capital expenditures, when these costs are recovered through depreciation allowances) so that revenues during each period should match expenses attributable to that period. In addition, these generally accepted principles call for utility customers to be charged with a reasonable cost of service during the period that they received such service. The implementation of these ratemaking principles, gives the utility an opportunity to earn the allowed equity return adjudicated in its rate case.

Q. As a utility financial executive, what do you consider to be the optimal use of securitization?

A. As a financial executive with one of the largest utilities in the country, Consolidated Edison, there were several occasions, in retrospect, where I would have been extremely pleased at the possibility of having securitization as a means of accessing the capital markets.

The first instance was in 1974 when the oil embargo caused by the quadrupling of oil prices resulted in a huge cash flow crisis for Con Ed. This caused Con Ed to omit its dividend, which triggered a very steep drop in utility stock prices. Con Ed was also closed out of the public debt markets for a number of years. To raise cash to finance its on-going distribution capital program, Con Ed was forced to sell two of its power plants to the New York State Power Authority. Securitization would have been extremely useful and the appropriate solution at that time.

The second instance was the deregulation of the utility industry in the 1990's. New York State forced its regulated utilities to divest their generation and purchase their power needs on the open market. Con Ed sold its power plants, leaving behind significant unrecovered stranded costs. In complicated rate agreements, Con Ed recovered most of these of costs over extended periods of time, and Con Ed's ratepayers effectively paid for power plants no longer under Con

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Ed's ownership or control. Once again, securitization could have solved some difficult financial issues.

At the time of generation divestiture, Con Edison, with Mr. Fichera's assistance, explored securitization. It was ultimately rejected it because necessary state legislation (that Mr. Fichera describes in his testimony) did not exist in New York at the time. Specific enabling legislation would have made the securitized debt "bullet proof" and acceptable to rating agencies and investors, resulting in the lowest possible debt rate for the benefit of consumers. With the utilities and the commission working together, we could have achieved that superior result.

Q. What lessons did you learn from these experiences?

A. The primary lessons that I learned were that securitization is best suited:

1. As a tool to help utilities with financial difficulties or other challenges and in need of cash flow, or
2. To avoid large rate increases to recover operating or capital costs incurred in the past on behalf of the ratepayer.

Q. Have these lessons been used in California?

A. Yes. In 2005, the California Public Utilities Code was amended to authorize PG&E to issue $3.0 billion of securitized energy recovery bonds to refinance the utility's regulatory asset. Securitization provided the necessary cash flow to allow it to emerge from bankruptcy and, over time, gain a more favorable credit rating which would reduce the cost of capital to PG&E. Consumer groups proposed the refinancing of this "regulatory asset" with securitization, giving the cash to PG&E up front in return for a reduced cost of carry for the regulatory asset. Only after extensive discussions between the utility and the consumer groups did a settlement occur, and in a Modified Settlement Agreement both sides agreed to request securitization authorization from the legislature. PG&E agreed to propose it. Without that agreement, I do not believe securitization could have been used by PG&E for the reasons discussed later in my testimony.

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Q. Can you give any other example in California?

A. Yes. Following deregulation in 1996, the California Public Utilities Code was amended to authorize the issuance of securitized debt to recover the above market costs of generation and related costs, and to facilitate a rate reduction for residential and small commercial customers.

Q. What do you conclude about these two scenarios?

A. California did the right thing for the right reasons.

Q. What is your opinion of a proposal to authorize the use of securitization "to reduce the cost of Utility Owned Generation recovered through the PCIA" (Power Charge Indifference Adjustment)?

A. Based upon close to three decades of experience in utility financial matters, rate case proceedings and communications with investors and Wall Street analysts, I have the following opinions:

1. When properly structured, as described by Mr. Sutherland and Mr. Fichera, securitization can raise capital at attractive rates and provide much needed cash flow. It can be very beneficial to utilities and its ratepayers. We have seen these benefits across the country for more than two decades as described in detail by Mr. Fichera.
2. Securitization can also be extremely beneficial to California utilities and its ratepayers, as the testimony of Paul Sutherland clearly delineates.
3. Securitization is a valuable financial tool to have available when viewed in the context of the current financial condition of PCG and EIX. These utilities are struggling financially and face pressure on bond ratings and an increased level of financial risk like the issues that Con Ed faced in the 1970's. In fact, PCG has already omitted its dividend precisely as Con Ed had to do. Mr. Abramson's testimony describes the tenuous position of these utilities and the capital markets' perception of their risk profile.
4. Securitization to refinance the operating power plants, although providing rate reductions, should be part of a larger discussion of the financial pressures faced by these utilities. In a

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vacuum, securitizing these power plants without a broader approach could be viewed as counterproductive. Private sector capital might react in a negative manner as described by Mr. Abramson.

5. Utilities and their stakeholders (including regulators) need to consider securitization as a valuable financing tool to bring into the mix when negotiating comprehensive rate settlements. My many years of rate case experiences has taught me that the best "win-win" is through good faith discussion of all available options rather than confrontation. Previous state statutes providing a legal framework for securitization have generally permitted securitized debt to be issued only upon an application by the affected utility.

Q. Would it be beneficial for all parties to consider securitization in California now?

A. Yes, absolutely, and it is my strong recommendation as a former utility finance executive that they do. As the testimony of Mr. Sutherland and Mr. Fichera demonstrates, securitization is a powerful financing tool that has benefited ratepayers and utilities over the years. It is a tool I would have liked to have had as Treasurer of Con Ed.

Mr. Sutherland provides a detailed discussion and quantification of the benefits to consumers and the utilities of securitizing the utility-owned generation (UOG). These benefits are real and quantifiable and should not be ignored or dismissed. Similar benefits may be achieved by securitizing the above-market power supply costs in long-term PPAs. The parties should explore how to achieve these benefits in a manner acceptable to all and as part of a global review of the financial issues facing the utilities.

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Q. There are generally accepted regulatory principles that recognize an "optimal" capital structure for utilities regarding the mix of debt, preferred stock and equity. Should securitization now be considered as part of the optimal capital structure?

A. Yes, possibly. Since the tool has been available and tested over the last 20 years, it has proven to be a durable and acceptable form of financing that has become more efficient over time. It has not been part of the optimal capital structure but going forward all parties might consider this tool as part of "traditional utility finance." Saber Partners' review of the context and conditions of securitization for California utilities shows its importance in future discussions and in mutually agreed proposals that might be made to the commission.

Q. Do you have an example of how this collaborative process that you describe can be beneficial?

A. I would refer you to my testimony concerning the securitization by Duke Energy Florida (DEF) of its retired nuclear power plant. DEF proposed and negotiated a settlement with the Commission staff and intervenors that allowed its investors to recover the costs of the retired plant and at the same time provided more than $600 million of net present value (NPV) benefits to ratepayers; clearly a big "win-win." The capital markets viewed this transaction in a positive manner, further protecting ratepayers from increased capital costs and allowing DEF to raise debt capital in the future at reasonable rates.

Achieving a consensus on securitization would be a powerful step in providing California consumer benefits and enhancing the financial condition of the utilities (which also benefits consumers through lower capital costs). The process requires all parties to work together with securitization experts and the affected utilities to develop a plan that uses securitization "best practices" to maximize the benefits to consumers.

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Q. Can you give an example of a circumstance in which utilities might apply for securitization?

A. Yes.

There were two occasions at which I and others at Con Ed would have preferred to have used securitization if there only had been a New York State statute in place authorizing it. As I described above, these occasions were: (1) the 1974 oil embargo which caused a sudden and huge cash flow crisis for Con Ed; and (2) deregulation of the electric utility industry in the 1990's when New York State forced its regulated utilities to divest their generation and purchase their power needs from the open market.

Q. If securitization were agreed to by PG&E and SCE, are there any special issues that the CPUC should consider?

A. As I testified before the Florida Commission, the Commission needs to have direct involvement in all steps of the securitization process, following the "best practices" in Mr. Fichera's testimony. There is ample precedent for this in other utility securitizations with superior results to securitization transactions that have not followed these "best practices." CPUC involvement will provide it with the essential information to approve the securitization issuance as unequivocally protecting ratepayers' interests and helping achieve the lowest overall cost for the financing.

In my Florida testimony, I strongly supported the need for a "Bond Team," which gives the Commission the necessary tools and information to be actively engaged in the pricing strategy and the marketing process. My Florida testimony goes on to describe how many commissions, including Florida, have been actively involved in the structuring, marketing and pricing of securitized utility bonds.

Active and visible Commission involvement in the full process is essential. Securitization cannot be left solely to the utilities to implement because the nature of the negotiation between the potential investors and the utilities is different than that which exists in a

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traditional utility debt financing. Since the securitization debt is not on the utilities balance sheet for credit purposes and shareholders are not at risk for any of the costs, there may not be the same incentive to achieve the lowest cost financing when selling securities to private investors. Consequently, the ratepayer also needs to be represented in the process with the utilities and that means active Commission involvement throughout the structuring, marketing and pricing of the bonds.

Q. If enabling State of California legislation were in place, would you recommend PG&E or SCE apply for securitization financing?

A. Yes, the financing tool needs to be made available now. For example, PG&E's Annual Report for 2017 on SEC Form 10-K (https://www.sec.gov/Archives/edgar/data/75488/000100498018000003/form10k.htm) provides extensive "Risk Factor" disclosure about threats to PG&E's cash flow and access to the capital markets in connection with recent wildfires. That "Risk Factor" disclosure is reproduced as Exhibit A. It includes the following caution:

> "On December 21, 2017, Moody's Investor Services and on December 22, 2017, Standard & Poor's Global Ratings, each placed all the ratings of PG&E Corporation and the Utility under review for downgrade, and Standard & Poor's Global Ratings additionally lowered its ratings on the Utility's preferred stock. If PG&E Corporation's or the Utility's credit ratings were to be downgraded or the ratings on the Utility's preferred stock are further downgraded, in particular to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced, or lack of, access to the commercial paper market and additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need."

It is in precisely such circumstances that California utilities should be strongly in favor of the possibility of utilizing securitization as a financial tool. But that will be possible only if enabling State of California legislation is in place.

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Q. Would PG&E and SCE also benefit from the use of securitization to buydown existing above-market PPAs?

A. Yes. As Mr. Sutherland points out, in recent years, credit rating agencies have begun to analyze long-term PPAs as though they were, in part, debt of the purchasing utility, even though periodic costs of PPAs are "pass throughs" to the ratepayers. This exposes PCG/PG&E and EIX/SCE to the risk that the credit ratings on their other debt and equity securities will be reduced. This can be mitigated if PG&E's and SCE's annual payment obligations pursuant to their PPAs are materially reduced through securitization financing.

In recognition of these considerations, in 2006 and 2008 cost of capital proceedings (Decision No. 05-12-043 and Decision No. 07-12-049), for example, the CPUC increased the return on equity (ROE) for PG&E, SCE and SDG&E between 40 and 70 basis points to reflect the debt equivalency of electric power procurement risks. In the 2013 cost of capital proceeding (Decision No. 12-12-034), the CPUC did not grant any debt equivalency premium, stating that procurement risk already is reflected in the parties' financial modeling results. However, the CPUC authorized ROEs toward the upper end of the ROE range that was found to be fair and reasonable to compensate utilities for financial, business and regulatory risks. See CPUC Policy & Planning Division "An Introduction to Debt Equivalency" (August 4, 2017) attached as Exhibit B to this testimony.

As a former utility Treasurer this would be another solid reason that I would want securitization as an available financial tool.

Q. Can you summarize your recommendations?

A. Yes. I recommend that the parties to this proceeding seek State of California legislation authorizing the issuance of securitized utility bonds as described in my testimony and in the testimony of Mr. Fichera, Mr. Sutherland and Mr. Abramson.

Q. Does this conclude your testimony?

A. Yes.

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Exhibits for Testimony of

Hyman Schoenblum, Senior Advisor

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EXHIBIT A

PG&E 2017 Annual Report

Risk Factor Disclosure

Risks Related to Wildfires

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires. PG&E Corporation and the Utility also expect to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the multiple wildfires that spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City, beginning on October 8, 2017 (the "Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44.

The Utility incurred $219 million in costs for service restoration and repair to the Utility's facilities (including $97 million in capital expenditures) through December 31, 2017 in connection with these fires. While the Utility believes that such costs are recoverable through CEMA, its CEMA requests are subject to CPUC approval. The Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs.

The fires are being investigated by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. The Utility expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the ways that they progressed. The CPUC's SED also is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating certain of the fires. (For example, on February 3, 2018, it was reported that investigators with the Santa Rosa Fire Department had completed their investigation of two small fires that reportedly destroyed two homes and damaged one outbuilding and had concluded that the Utility's facilities, along with high wind and other factors, contributed to those fires.) It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigation is complete.

As of January 31, 2018, the Utility had submitted 22 electric incident reports to the CPUC associated with the Northern California wildfires where Cal Fire has identified a site as potentially involving the Utility's facilities in its investigation and the property damage associated with each incident exceeded $50,000.

The information contained in these reports is factual and preliminary, and does not reflect a determination of the causes of the fires. The investigations into the fires are ongoing.

If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. (See "The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially negatively affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows" below.) In addition to such claims for property damage, interest and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations.

Given the preliminary stages of investigations and the uncertainty as to the causes of the fires, PG&E Corporation and the Utility do not believe a loss is probable at this time. However, it is reasonably possible that facts could emerge through the course of the various investigations that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in an accrued liability in the future, the amount of which could be material. PG&E Corporation and the Utility currently are unable to reasonably estimate the amount of losses (or range of amounts) that they could incur, given the preliminary stages of the investigations and the uncertainty regarding the extent and magnitude of potential damages. On January 31, 2018, the California Department of Insurance issued a press release announcing an update on property losses in connection with the October and December wildfires in California, stating that, as of such date, "insurers have received nearly 45,000 insurance claims totaling more than $11.79 billion in losses," of which approximately $10 billion relates to statewide claims from the October 2017 wildfires. The remaining amount relates to claims from the Southern California December 2017 wildfires. According to the California Department of Insurance, as of the date of the press release, more than 21,000 homes, 3,200 businesses, and more than 6,100 vehicles, watercraft, farm vehicles, and other equipment were damaged or destroyed by the October 2017 wildfires. PG&E Corporation and the Utility have not independently verified these estimates. The California Department of Insurance did not state in its press release whether it intends to provide updated estimates of losses in the future.

If the Utility's facilities are determined to be the cause of one or more of the Northern California wildfires, PG&E Corporation and the Utility could be liable for the related property losses and other damages. The California Department of Insurance January 31, 2018 press release reflects insured property losses only. The press release does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Utility were to be found liable for certain or all of such other costs and expenses, the amount of PG&E Corporation's and the Utility's liability could be higher than the approximately $10 billion estimated in respect of the wildfires that occurred in October 2017, depending on the extent of the damage in connection with such fire or fires. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

PG&E Corporation and the Utility also are the subject of a still increasing number of lawsuits that have been filed against PG&E Corporation and the Utility in Sonoma, Napa and San Francisco Counties' Superior Courts, several of which seek to be certified as class actions. The lawsuits allege, among other things, negligence, inverse condemnation, trespass, and private nuisance. They principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the fires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, two derivative lawsuits for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively. PG&E Corporation and the Utility expect to be the subject of additional lawsuits in connection with the Northern California wildfires. The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $800 million. If the Utility were to be found liable for one or more fires, the Utility's insurance could be insufficient to cover that liability, depending on the extent of the damage in connection with such fire or fires.

In addition, it could take a number of years before the Utility's final liability is known and the Utility could apply for cost recovery. The Utility may be unable to recover costs in excess of insurance through regulatory mechanisms and, even if such recovery is possible, it could take a number of years to resolve and a number of years thereafter to collect. Further, SB 819, introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities from recovering costs in excess of insurance resulting from damages caused by such utilities' facilities, if the CPUC determines that the utility did not reasonably construct, maintain, manage, control, or operate the facilities. PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. (See "If the Utility is unable to recover all or a significant portion of its excess costs in connection with the Northern California wildfires and the Butte fire through ratemaking mechanisms, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected" below.)

Losses in connection with the wildfires would likely require PG&E Corporation and the Utility to seek financing, which may not be available on terms acceptable to PG&E Corporation or the Utility, or at all, when required. (See "Risks Related to Liquidity and Capital Requirements" below.)

As of December 31, 2017, neither PG&E Corporation nor the Utility has accrued a liability with respect to the Northern California wildfires. If PG&E Corporation and the Utility were to determine that it is both probable that a loss has occurred and the amount of loss can be reasonably estimated, a liability would be recorded consistent with applicable accounting principles and as described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8. As noted above, to the extent that such determination is made and a liability is accrued with respect to the Northern California wildfires, the amount of such liability accrual may be substantial. To the extent not offset by insurance recoveries determined to be similarly probable and estimable, the liability would reduce the balance sheet equity of PG&E

Corporation and the Utility, which could adversely impact the Utility's ability to maintain its CPUC-authorized capital structure of 52% equity and 48% debt and preferred stock, and which could also adversely impact PG&E Corporation's and the Utility's credit ratings and their ability to declare and pay dividends, efficiently raise capital, comply with financial covenants, and meet financial obligations. (See "PG&E Corporation's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings" below.)

Uncertainties relating to and market perception of these matters and the disclosure of findings regarding these matters over time, also could continue or increase volatility in the market for PG&E Corporation's common stock and other securities, and for the securities of the Utility, and materially affect the price of such securities.

PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by the ultimate amount of third-party liability that the Utility incurs in connection with the Butte fire.

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a gray pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

In connection with the Butte fire, complaints have been filed against the Utility, currently involving approximately 3,770 individual plaintiffs representing approximately 2,030 households and their insurance companies. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also seek punitive damages. The number of individual complaints and plaintiffs may still increase in the future, because the statute of limitations for property damages in connection with the Butte fire has not yet expired. (The statute of limitations for personal injury in connection with the Butte fire has expired.) The Utility continues mediating and settling cases.

In addition, on April 13, 2017, Cal Fire filed a complaint seeking to recover $87 million for its costs incurred in connection with the Butte fire, and in May 2017, the OES indicated that it intends to bring a claim against the Utility that the OES estimated in the approximate amount of $190 million. Also, in June 2017, the County of Calaveras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 million.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the doctrine of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. While the Utility believes it was not negligent, there can be no assurance that a court or jury would agree with the Utility.

The Utility currently believes that it is probable that it will incur a loss of at least $1.1 billion, increased from the $750 million previously estimated as of December 31, 2016 in connection with the Butte fire. While this amount includes the Utility's assumptions about fire suppression costs (including its

assessment of the Cal Fire loss), it does not include any significant portion of the estimated claims from the OES and the County of Calaveras. The Utility still does not have sufficient information to reasonably estimate the probable loss it may have for these additional claims. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows. (See Note 13 to the Consolidated Financial Statements in Item 8.)

If the Utility is unable to recover all or a significant portion of its excess costs in connection with the Northern California wildfires and the Butte Fire through ratemaking mechanisms, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

Through December 31, 2017, the amounts accrued in connection with claims relating to the Butte fire have exceeded the Utility's liability insurance coverage. While the Utility filed an application with the CPUC requesting approval to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs that have not otherwise been recovered through insurance or other mechanisms, the Utility cannot predict the outcome of this proceeding. (See "Regulatory Matters – Application to Establish a Wildfire Expense Memorandum Account" in Item 7. MD&A.)

In addition, there can be no assurance that the Utility will be allowed to recover costs recorded in WEMA, if approved, in the future. While the CPUC previously approved WEMA tracking accounts for San Diego Gas & Electric Company in 2010, in December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUC's prudent manager standard. That determination is being challenged by San Diego Gas & Electric as well as by the Utility and Southern California Edison.

Additionally, SB 819 introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities' recovery of costs in excess of insurance resulting from damages caused by such utilities' facilities, if the CPUC determines that the Utility did not reasonably construct, maintain, manage, control, or operate the facilities.

PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover all or a significant portion of costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows.

California law includes a doctrine of inverse condemnation that is routinely invoked in California for wildfire damages. Inverse condemnation imposes strict liability (including liability for attorneys' fees) for damages as a result of the design, construction and maintenance of utility facilities, including utilities'

electric transmission lines. Courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefitted from such undertaking, and based on the assumption that utilities have the ability to recover these costs from their customers. Plaintiffs have asserted the doctrine of inverse condemnation in lawsuits related to the Northern California and Butte fires, and it is possible that plaintiffs could be successful in convincing courts to apply this doctrine in these or other litigations. For example, on June 22, 2017, the Superior Court for the County of Sacramento found that the doctrine of inverse condemnation applies to the Utility with respect to the Butte fire. Although the Utility has filed a renewed motion for a legal determination of inverse condemnation liability, there can be no assurance that the Utility will be successful in its arguments that the doctrine of inverse condemnation does not apply in the Butte fire or other litigation against PG&E Corporation or the Utility.

Furthermore, a court could determine that the doctrine of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. Although the imposition of liability is premised on the assumption that utilities have the ability to automatically recover these costs from their customers, there can be no guarantee that the CPUC would authorize cost recovery whether or not a previous court decision imposes liability on a utility under the doctrine of inverse condemnation. In December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUC's prudent manager standard. That determination is being challenged by San Diego Gas & Electric as well as by the Utility and Southern California Edison.

If PG&E Corporation or the Utility were to be found liable for damage under the doctrine of inverse condemnation, but is unable to secure a cost recovery decision from the CPUC to pay for such costs through increases in rates, the financial condition, results of operations, liquidity and cash flows of PG&E Corporation and the Utility would be materially affected by potential losses resulting from the impact of the Northern California wildfires. (See "PG&E Corporation and the Utility also expect to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions" and "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected by the ultimate amount of third-party liability that the Utility incurs in connection with the Butte fire" above.)

* * *

PG&E Corporation's and the Utility's financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.

PG&E Corporation and the Utility will continue to seek funds in the capital and credit markets to enable the Utility to make capital investments, and to pay fines that may be imposed in the future, as well as costs related to rights-of-way and legal and regulatory costs. PG&E Corporation's and the Utility's ability to access the capital and credit markets and the costs and terms of available financing depend primarily on PG&E Corporation's and the Utility's credit ratings and outlook. Their credit ratings and outlook can be affected by many factors, including pending or anticipated litigation, the pending Cal Fire and CPUC investigations and CPUC ratemaking proceedings, and by the December 20, 2017 decision of the Boards of Directors of PG&E Corporation and the Utility to suspend dividends, as well as the perceived impact of all such matters on PG&E Corporation's and the Utility's financial condition, whether or not such perception is accurate. On December 21, 2017, Moody's Investor Services and on

December 22, 2017, Standard & Poor's Global Ratings, each placed all of the ratings of PG&E Corporation and the Utility under review for downgrade, and Standard & Poor's Global Ratings additionally lowered its ratings on the Utility's preferred stock. If PG&E Corporation's or the Utility's credit ratings were to be downgraded or the ratings on the Utility's preferred stock are further downgraded, in particular to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced, or lack of, access to the commercial paper market and additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, an increase in interest rates by the Federal Reserve Bank, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about matters discussed under "Enforcement and Litigation Matters" in Item 3. Legal Proceedings and Note 13 of the Notes to the Consolidated Financial Statements in Item 8. The negative publicity and the uncertainty about the outcomes of these matters may undermine confidence in management's ability to execute its business strategy and restore a constructive regulatory environment, which could adversely impact PG&E Corporation's stock price. Further, the market price of PG&E Corporation common stock could decline materially depending on the outcome of these matters. The amount and timing of future share issuances also could affect the stock price.

EXHIBIT B

An Introduction to Debt Equivalency

California Public Utilities Commission
Policy & Planning Division

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I. Introduction

With the growth of wholesale markets many utilities rely on long-term purchase power agreement (PPA) to meet the power supply needs of their customers. A PPA represents a long-term financial obligation. Under a long-term PPA the utility is obligated to make fixed payments for available capacity or take-or-pay energy payments over multiple years.

PPAs have both benefits and risks to the utility. Utilities have a choice of either signing PPAs or finance and build their own generation. By entering into a PPA the utility shifts construction and operating risks such as operating cost overruns, performance shortfalls, and technology obsolesce to the suppliers. Another benefit of PPA to the utility is that it allows diversity in procurement.

The principal risk borne by a utility that relies on PPAs is the recovery of financial obligations in rates. The utility that relies on a PPA will have a fixed payment obligation without an associated debt obligation reported on its balance sheet. The fixed payment obligation creates financial risk for purchasing utility. For example, the PPA payment obligation means less cash will be available to make payments to bondholders.

- ***This report explores the issue of Debt Equivalency by explaining why it is important and reviews options for addressing it.***

Under generally accepted accounting principles, utilities do not report PPA obligations in their balance sheets as debt, but credit-rating agencies treat the utility's commitments under PPAs as debt-like financial obligations. "Debt Equivalency" is a term used by credit analysts to describe the debt-like financial obligations resulting from signing long-term contracts. Credit-rating agencies incorporate Debt Equivalency in their credit analysis.

Utilities in California have raised the issue of Debt Equivalency in different proceedings. The Commission's long standing position is that the impact of Debt Equivalency on utilities' financial condition should be addressed in Cost of Capital proceedings. In addition in Long-term Procurement proceedings the Commission has been considering the Debt Equivalency impact of new long-term commitments in the contract selection and approval process in some cases.

The Commission has acknowledged that rating agencies impute debt from long-term PPAs and incorporate that in their credit analysis. But the Commission has not adopted a comprehensive policy on the cost recovery treatment of Debt Equivalency. In Cost of Capital proceedings the Commission has ruled that Debt Equivalency should be assessed on a case-by-case basis along with other financial, regulatory and operational risks in setting a balanced capital structure and fair return on equity (ROE).

The Commission has applied the strategy of setting a balanced capital structure and fair ROE on case-by-case basis differently over the years. In 2006 and 2008 Cost of capital decision (D.05-12-043 and D.12-12-034) the strategy resulted in increasing the ROE range by a Debt Equivalency premium to

compensate utilities for the risk of PPAs. In addition the Commission approved an ROE toward the upper end of the parties' proposed ROE range.

In contrast in the 2013 Cost of capital decision, the approach resulted in choosing an authorized ROE at the top of the ROE range with no additional increases in the ROE range. The Commission did not grant a Debt Equivalency premium for test year 2013 even though in the 2013 Cost of Capital Decision, D. 12-12-034, the Commission acknowledged that there had been an increase in the number of procurement transactions the utilities were entering into.[1]

The Debt Equivalency premiums that the Commission granted for test year 2006 and 2008 can explain a large part of what has become known as California Premium. The major utilities in California have been earning a return on equity (ROE) higher than the national average. The Debt Equivalency premiums granted for test year 2006 and 2008 together covered a 7 year period from 2006 through 2012.

The remainder of this report is divided into seven parts. Section II discusses why Debt Equivalency is important. Section III discusses how Debt Equivalency is addressed by credit rating agencies. Section IV describes S&P methodology for incorporating Debt Equivalency into credit ratings analysis. Section V describes S&P methodology for mitigating the impact of Debt Equivalency. Section VI describes how the issue of Debt Equivalency has been addressed by the Commission. Finally section VII summarizes the findings.

II. Why is it important?

Debt equivalency is a term used by credit analysts to describe the financial risk inherent in the fixed financial obligation resulting from signing long-term contracts, such as PPA or operating leases. Although such contractual commitments are not reported on the balance sheet as debt, credit rating agencies view them as having risk characteristics similar to debt. Credit-rating agencies therefore treat the utility's commitments under PPAs as a substitute for debt-financed capital investments in generation capacity in assessing credit risk.

Overall Credit rating agencies agree that PPAs expose the buyer to the financial risk not reflected on the balance sheet as debt (i.e. uncertainty surrounding cost recovery of a long-term commitment). On the positive side, credit rating agencies view PPAs as part of a balanced power supply portfolio approach that allows diversity to procurement, and limits operational risks associated with generation capacity ownership. Understanding Debt Equivalency is therefore important because of its implications for accurately assessing credit risks and related costs associated with long-term contractual commitments such as PPAs.

To achieve comparability between utilities that finance and build generation capacity and those that purchase contractual rights to capacity to satisfy new load, credit rating agencies adjust financial

[1] D. 12-12-034, page 33.

measures to incorporate PPA fixed obligation even though these obligations are not shown as liabilities on the balance sheet. More specifically credit rating agencies have developed procedures for calculating Debt Equivalency and imputing its impact on financial ratios used to measure a utility's creditworthiness.

The financial risk resulting from a large portfolio of PPAs could lead to a credit rating downgrade. The weakened credit ratings, in turn, affect utilities' cost of debt and equity assessed by financial markets. Therefore PPAs or other types of debt equivalent obligations might affect a utility's overall cost of capital.

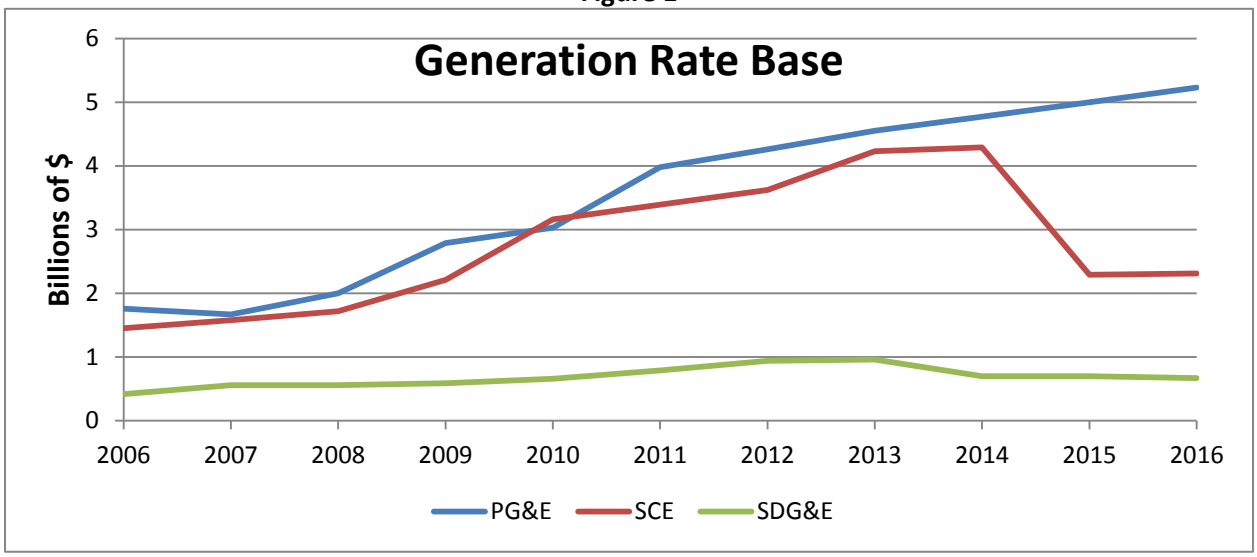
In addition to impacting utilities cost of capital, from investors' perspective, PPAs may limit a utility's ability to grow earnings. The traditional rate-base/rate of return regulatory model provides powerful incentives for utilities to build generation. In rate of return regulatory model utilities earn a return on rate base, which primarily consist of plant in service less accumulated depreciation. Cost of service regulation allows utilities the opportunity to earn a return on utility own generation (UOG) but does not allow utilities to earn a return on PPA. Therefore, from an investors' perspective by limiting a utility's ability to grow rate base, PPAs limit a utility's ability to grow earnings.

In other words, PPAs by replacing UOG restrict the total amount of allowable profits, which in turn might impact how investors view the utility's stock price. Regulators can consider addressing utilities bias to own generation rather than purchase power by developing a performance based mechanism to offset this bias.

Utilities in California have transitioned from owning and operating most of their electric generation needs to purchasing generation from other parties under PPAs. The substantial increase in the number of procurement transactions has dampened utilities investment in generation. The question is whether that has also limited their abilities to grow earnings.

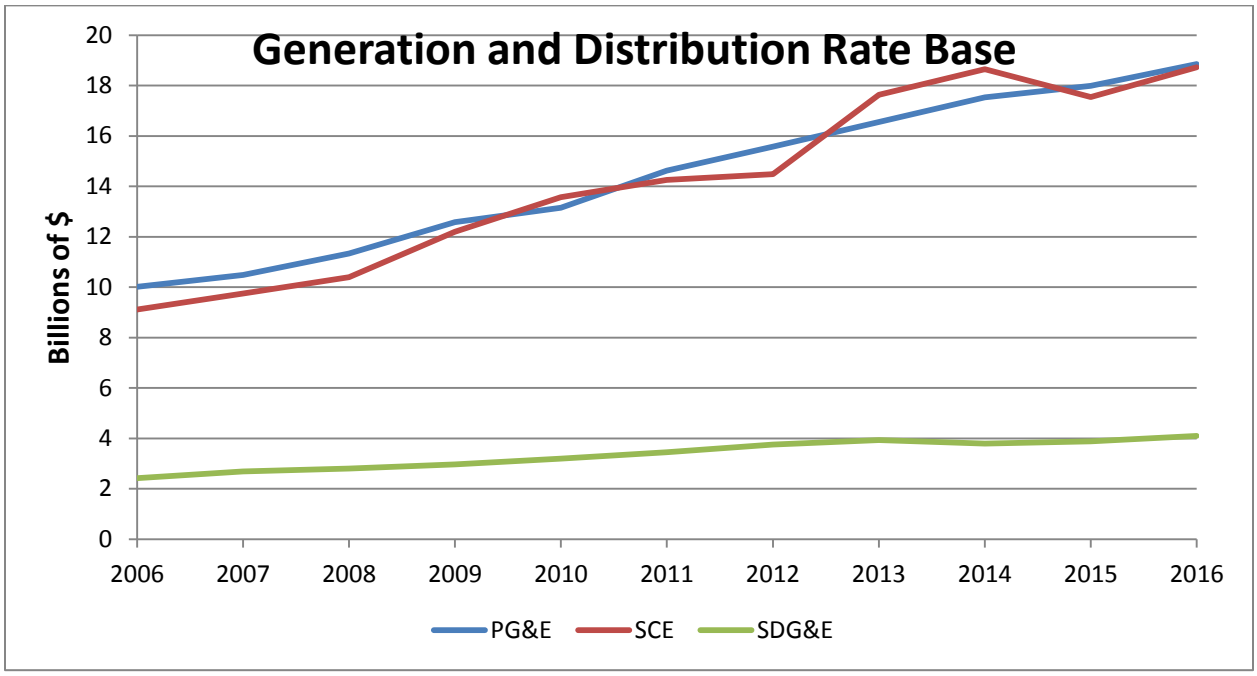
Figure 1 shows PG&E, SCE and SDG&E's generation rate base overtime. As the Figure illustrate for PG&E generation rate base has been increasing overtime. But for SCE and SDG&E generation rate base has declined overtime. The decline for SCE is especially significant. However the decline in the generation rate base for SCE and SDG&E has been more than offset by the growth in distribution rate base. As Figure 2 illustrates when electric distribution rate base is added to generation rate base the trend is upward sloping for all three major IOUs in California. In Figure 3 the total electric rate base, which includes transmission rate base, has a steeper upward slope for all the major IOUs in California.

Figure 1



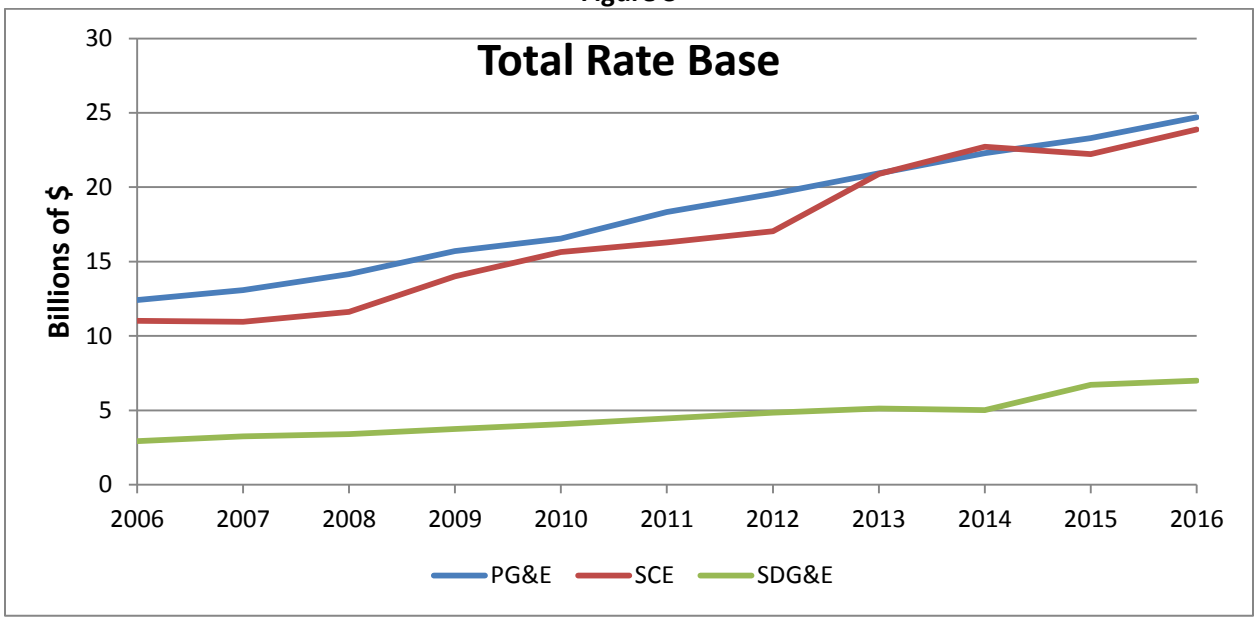
Based on data collected by the Energy Division

Figure 2



Based on data collected by the Energy Division

Figure 3



Based on data collected by the Energy Division

The following sections will present credit rating agencies' view on Debt Equivalency. More specifically the following sections will present credit rating agencies' view on the following threshold issues:

- How to measure Debt Equivalency,
- How to calculate Debt Equivalency impact,
- What types of adjustment are needed to mitigate the impact of PPAs.

III. How Debt Equivalence is measured?

All three credit rating agencies, S&P, Moody's, and Fitch Ratings (Fitch), assign Debt Equivalency to capacity payments. All three also agree that PPA exposes buyer to the uncertainty surrounding cost recovery of long-term financial commitments not reflected as debt on the balance sheet. Among the three, S&P places the greatest emphasis on Debt Equivalency and has published detailed methodology.

The Debt Equivalency value is calculated as the present value of the capacity payment, discounted at the utility's average cost of debt, and multiplied by a risk factor. The risk factor is intended to reflect the probability that PPA costs will be fully recovered in rates and varies depending on state-specific regulatory or legislative cost-recovery mechanisms. The present value of the capacity payment may also be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio. Where those mitigating factors are present, the risk factor can reduce the imputed debt equivalence amount.

Credit rating agencies have different methodologies for calculating a risk factor. Next credit rating agencies' methodology for estimating a risk factor will be explained.

1. Risk Factor

Credit rating agencies apply different methodology for estimating a risk factor. Risk factors can range between 0% and 100%. A 100% risk factor would signify that substantially all risk related to cost recovery of contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity.

For utilities S&P typically assigns risk factors between 0% and 50% based on different factors including; (1) regulatory environment that can range from favorable to unfavorable, (2) mechanisms to recover costs such as automatic recovery (can vary depending on whether recovery takes place in a timely manner, with more certainty and is complete) or legislative mandate, (3) counterparty risk based on performance history and credit quality.

Recovery mechanism policies which provide assurances of cost recovery mitigate the credit risk impact of debt equivalency for S&P. In rate cases, risk factor assigned by S&P can have a value around 50%. With the increased likelihood of recovery under power purchase adjustment mechanism for all prudent PPA costs, a risk factor of 25% is employed. And in case of legislative mandate risk factor can have a value between 0% and 15%.[2] For utilities in California where cost recovery is under power purchase adjustment mechanisms for all prudent PPA costs, S&P uses a risk factor equal to 25%.

Moody's does not apply a formula. Instead Moody's conducts qualitative assessment of inherent risk to determine the degree to which company's financial flexibility is affected by PPAs. Therefore, Moody's approach is more subjective. "In certain cases, Moody's would not impute any debt and in other cases consider PPAs as a positive risk mitigation factor. Moody's recognizes that PPAs have been used by utilities as a risk management tool. Thus, it will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Moody's looks at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations."[3] Regulatory assurances for Moody's can result in risk factor equal to 0%. For California, Moody's does not always assign debt equivalency due to high probability of cost recovery.

Fitch assigns risk factor, which can range between 0 and 100%, based on (1) PPA cost relative to market (market to market value is calculated based on forecast), (2) likelihood of cost recovery taking into account lags in regulatory recovery and probability of disallowances, (3) counterparty credit quality i.e. risk of seller's default. Fitch focuses on out-of- money positions with low cost recovery prospects. For California, Fitch does not always assign debt equivalency due to high probability of cost recovery.

[2] Key Credit Factors for the Regulated Utilities Industry, Standard & Poor's, November 19, 2013.
[3] D12-12-034

In the next section S&P methodology for estimating the impact of Debt Equivalency on credit ratings will be explained.

IV. S&P Methodology for estimating the impact of Debt Equivalence

To discuss the process of assigning Debt Equivalence to capacity payments, in this section, S&P methodology is explained. S&P places the greatest emphasis on Debt Equivalence of all the rating agencies and has published a detailed methodology.

The first step involves an estimation of the annual capacity payments that have to be made under the contract. S&P does not capitalize the energy component of the contract because of the need to equate the comparison between utilities that buy vs. build, i.e. S&P does not capitalize utility fuel contracts. In contracts where the capacity and energy components is not broken out separately, S&P's old methodology for estimating capacity payment was based on 50% of total payment. S&P's new methodology is based on implied capacity payment. Implied capacity payment is estimated by identifying an implied capacity price within an all-in energy price. The implied capacity payment, which is expressed in dollars per kilowatt-year, is found by multiplying implied price by the number of kilowatts under contract.[4]

Second, S&P re-characterizes a PPA obligation as the creation of an asset financed with debt. The implied creation of the asset represents the ownership-like attributes of the contracted PPA. S&P then estimates imputed debt, imputed interest and imputed depreciation associated with the implied creation of the asset.

Imputed debt increases the debt reported on the balance sheet by the present value of the stream of capacity payments multiplied by the risk factor. Equity is not adjusted because the implied creation of the asset is financed with debt. Total assets, as reported for financial accounting purposes, are increased for the implied creation of the asset by the amount of implied debt. S&P estimates an imputed interest associated with the imputed debt. Imputed interest expense increases income statement interest expense by the amount of imputed debt multiplied by the average cost of debt.

Furthermore S&P estimates an imputed depreciation associated with the implied creation of the asset that tempers the impact of PPAs on cash flow measures. The imputed depreciation is estimated as risk factor multiplied by capacity payment minus imputed interest expense. The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).

[4] Standard and Poor's Methodology for Imputing Debt for U.S. Utilities Power Purchase Agreements, Standard & Poor's, May 7, 2007.

Third, the imputed debt, Interest and depreciation are used to adjust on a pro forma basis the respective amounts reported for accounting purposes on the balance sheet and income statement. S&P uses the information from the pro forma financial statements to estimate financial ratios that are employed as part of the analysis to assign credit ratings. More specifically to evaluate default risk, S&P uses adjusted financial statements to calculate the following financial ratios:

1) Debt as a percentage of Total Capital,
2) Funds from Operations (FFO) to Debt,
3) FFO Interest Coverage = (FFO+ Interest Expense)/Interest Expense.

FFO is defined as net Income plus depreciation plus other net cash from operations plus imputed depreciation expense.

The adjusted financial ratios impact default risk or creditworthiness of the utility. Table 1 shows financial ratio guidelines that S&P uses for A, A- and BBB- rated utilities. A credit rating below BBB- is considered not investment grade. For S&P the link between Debt Equivalency and credit worthiness is direct since S&P relies primarily on quantitative factors.

Table 1: S&P Utility Group Financial Targets

Indicative Ratings	(FFO/Debt) %	(FFO/Interest)	(Total Debt/Capital) %
A	40-60	4.0-6.0	25-40
A-	25-45	3.0-4.5	35-50
BBB-	10-30	2.0-3.5	45-60

However, given the range of financial guidelines in Table 1, even for S&P the link depends on where the utility is positioned in its' ranking bracket. In other words, debt equivalence is more likely to have a direct impact in S&P approach when the financial ratios are closer to the minimum of the range. For example, if a utility has a BBB- financial risk indicator based upon its financial ratios, a change from a 58 percent debt-to-capital to one with 62 percent places the utility in the "Highly Leveraged" financial risk indicator category for that ratio and will likely results in a credit downgrade.

It should be pointed out that the link between Debt Equivalency and credit ratings for Moody's is indirect. Moody's resolves the rating implications on the case by case basis with reference to both qualitative and quantitative factors.

V. S&P Mitigation Methodology

S&P has developed three approaches for addressing mitigation of debt equivalency:

1) Adjusting utility's capital structure (equity ratio) to mitigate the impact of PPAs,
2) Adjusting utility's cost of equity (ROE) to mitigate the impact of PPAs,
3) Adjusting the PPA offers from third parties to reflect the impact PPAs. More specifically, to offset the negative effects of imputed debt, collect a return on amount of imputed equity as an adder to the PPA bids.

S&P has published its detailed methodology on Debt Equivalence mitigation. In what follows, the three mitigating methods developed by S&P are explained by way of an example of a company ABC. Assume ABC enters into a 30-year PPA for 1.5 million MWh at annual capacity payments of $50 million. Also assume ABC's risk factor is 25%.

Table 2 show capital structure and cost of capital (weighted average cost or WACC) of the company prior to entering the PPA contract. Total asset or rate base, $1000 million, consists of 50% debt and 50% equity. ABC's cost of debt is 5% and its' cost equity is 10%.

Table 2: Regulated Capital Structure and Cost of Capital Prior to PPA

	Amount ($)	%	Cost	WACC
Debt	$500	50%	5%	2.5%
Equity	$500	50%	10%	5.0%
Total	$1000	100%		7.5%

To incorporate the impact of Debt Equivalency, S&P imputes debt, interest and depreciation in the following manner:

Present Value of capacity payment is equal to $768.6 million ($\sum_{t=1}^{30} \quad \$50/(1+5\%)^t$),
Imputed debt is equal to $192.2 m ($768.6 x 25%),
Imputed interest is equal to $9.6 m ($192.2 x 5%),
Imputed depreciation is equal to $2.9 million ($50 x 25% - $9.6)

Table 3 shows the capital structure post-PPA contract including the impact of Debt Equivalency.

Table 3: Adjusted Capital Structure
Including Imputed Debt Post PPA

	Amount ($)	%
Debt	$692	58%
Equity	$500	42%
Total	$1192	100%

Comparison of Table 3 with Table 2 shows that inclusion of Debt Equivalency increases the percentage of debt in the capital structure by 8 percent.

1. Mitigation Method One: Increase the amount of equity in the rate base.

To restore the original capital structure, ABC issues new equity in the amount of $96 million and recalls debt in the amount of $96 million. Table 4 shows the capital structure after the mitigation with the imputed debt. As Table 5 shows this method of mitigation restores the original capital structure ratios (50% debt, 50% equity ratio) post-PPA contract.

Table 4: Capital Structure after Mitigation Including DE

	Amount ($)	%
Debt	596	50%
Equity	596	50%
Total	1192	100%

Table 6 shows company ABC actual capital structure and cost of capital post-PPA contract excluding the imputed debt. As Table 5 shows this method by increasing the percentage of more expensive type of capital, common stocks, and reducing the percentage of less expensive type of capital, debt, increases cost of capital.

Table 5: Capital structure and WACC post-PPA contract excluding DE

	$	%	Cost	WACC
Debt	404	40.40	5%	2.02%
Equity	596	59.60	10%	5.96%
Total	1000	100%		7.975%

Comparison of Table 5 with Table 2 demonstrates the impact of this particular mitigation effort on cost of capital. Cost of capital increases by $4.75 million, which is the difference between the pre-PPA and post-PPA WACC times total asset or rate base, $1000, ((7.975%-7.5%)*1000 = $4.75).

Table 6 shows the impact of the mitigation effort on financial ratios S&P employs to assign credit ratings. The mitigation effort fully restores debt ratio and EBIT Interest coverage ratio and partly restores FFO/Interest, and FFO/Debt ratios. EBIT Interest coverage, which reflects how well interest charges are covered by operating income, is another important financial ratio. However the restoration is accomplished at a cost, since it is expensive to issue equity.

Table 6: Ratios Before and After PPA

	Before PPA	With PPA No Mitigation	With PPA & Mitigation
Debt/Capital	50%	58%	50%
FFO/Total Debt	0.25	0.18	0.22
FFO/Interest	6.00	4.70	5.45
EBIT/ Interest	3.20	2.67	3.10

2. Mitigation Method Two: Increase the allowed ROE such that pre-PPA WACC is equal to post-PPA WACC

In Table 2 the pre-PPA contract cost of capital (WACC) is 7.5%. To restore cost of capital (WACC) with imputed debt included in capital structure, as Table 7 demonstrates, the allowed return on equity has to increase to 10.95%.

Table 7
Adjusted Capital Structure Reflecting Imputed Debt and Constant WACC

	$	%	Cost	WACC
Debt	692	58	5%	2.9%
Equity	500	42	10.95%	4.6%
Total	1192	100		7.5%

Table 8 shows company ABC actual capital structure and cost of capital after the increase in return on equity without the imputed debt. As Table 8 shows, this method of mitigation increases cost of capital (from 7.5% to 7.975%) post-PPA contract.

Table 8: Capital Structure without Imputed Debt at Higher ROE

	$	%	Cost	WACC
Debt	500	50	5%	2.5%
Equity	500	50	10.95%	5.475%
Total	1000	100		7.975%

Comparison of Table 8 with Table 2 demonstrates the impact of this particular mitigation effort on cost of capital. Cost of capital increases by $4.75 million, which is the difference between the pre-PPA and post-PPA return on equity times the amount of equity in the rate base, $500, ((10.95%-10%)*500 = $4.75).

Table 9 shows the impact of the mitigation effort on financial ratios S&P employs to assign credit ratings. The mitigation effort does not fully restore any ratios. Therefore this method of mitigation is not

sufficient for utilities with low credit ratings. However, this mitigation method, by increasing the return on equity, does compensate shareholders for the increased risk of Debt Equivalency.

Table 9: Financial Ratios Before and After PPA

	Before PPA	With PPA No Mitigation	With PPA & Mitigation
Debt/Capital	50%	58%	58%
FFO/Total Debt	0.25	0.18	0.18
FFO/Interest	6.00	4.70	4.70
EBIT/Interest	3.20	2.67	2.67

Table 10 contrasts the first two mitigation methods. Although both methods result in equal amount of increase in revenue requirement, the first method is more expensive since it also involves transaction or floatation cost for issuing common stocks. Floatation cost is what investment banks charge to underwrite securities. Floatation cost mainly depends on the firm's risk and the particular type of capital being issued. Floatation cost is highest for common stocks.

Table 10: Method One vs. Method Two

	Method 1 Adjust ROE	Method 2 Adjust Equity Ratio
WACC	**7.98%**	**7.98%**
ROE	**10%**	**10.95%**
Revenue Requirement	**$4.75 m**	**$4.75 m**
Transaction Costs	**Present**	**Avoided**
Debt/Capital	**Restored**	**Not Restored**
FFO/Debt	**Partially Restored**	**Not Restored**
FFO/Interest	**Partially Restored**	**Not Restored**

3. **Mitigation Method Three**: Impute new equity to offset imputed debt, collect this via an adder to the PPA bid.

In this mitigation method the utility collects an additional return on equity through an adder to the PPA bid. The additional return is based on the imputed equity required to offset imputed debt. Imputed equity, equity return, and contract adder are calculated as:

Imputed Equity = Imputed Debt (Equity/Debt),*
*Equity Return = Imputed Equity*ROE,*
Contract adder = Equity Return/MWh per year

Table 11 shows the compensating equity, compensating ROE, and contract adder over the life of the contract using the PPA in our example. As Table 11 reflect the contract adder declines, as present value

of capacity payment and imputed debt decline overtime. In the first year of the contract the present value of capacity payment is $768.6, imputed debt and compensating equity are both $192.16 (debt to equity ratio is one), compensating ROE is $19.22 ($192.16*10%), and contract adder is $12.81 per MWh ($19.22/1.5 MWh).

The amount of compensating equity and return, in this method of mitigation, depends on the choice of ratio to restore. In other words, the company will have to issue more or less equity depending on which ratio is targeted. However, using this mitigation method, the debt ratio (debt/total capital) cannot be restored since equity is not actually issued.

The direct impact of this mitigation method is to compensate shareholders for the increased risk of Debt Equivalency. However this method is more expensive than the other two methods. The present value of contract adder over the life of the contract is $153.33 (using cost of debt as the discount rate). In contrast the present value of the total cost for the other two methods is $76.67.Therefore this method is more appropriate for a utility with low credit rating.

Table11: Method Three

Year	PV of Capacity Payment ($)	Imputed Debt $	Compensating Equity $	Compensating ROE $	Contract Adder ($/MWh)
1	768.6	192.16	192.16	19.22	12.81
2	757.1	189.26	189.26	18.93	12.62
3	744.9	186.23	186.23	18.62	12.42
4	732.2	183.04	183.04	18.30	12.20
5	718.8	179.69	179.69	17.97	11.98
6	704.7	176.17	176.17	17.62	11.74
7	689.9	172.48	172.48	17.25	11.50
8	674.4	168.61	168.61	16.86	11.24
9	658.2	164.54	164.54	16.45	10.97
10	641.1	160.26	160.26	16.03	10.68
11	623.1	155.78	155.78	15.58	10.39
12	604.3	151.07	151.07	15.11	10.07
13	584.5	146.12	146.12	14.61	9.74
14	563.7	140.93	140.93	14.09	9.4
15	541.9	135.47	135.47	13.55	9.03
16	519	129.75	129.75	12.97	8.65
17	494.9	123.73	123.73	12.37	8.25
18	469.7	117.42	117.42	11.74	7.83
19	443.2	110.79	110.79	11.08	7.39
20	415.3	103.83	103.83	10.38	6.92
21	386.1	96.52	96.52	9.65	6.43
22	355.4	88.85	88.85	8.88	5.92

23	323.2	80.79	80.79	8.08	5.39
24	289.3	72.33	72.33	7.23	4.82
25	253.8	63.45	63.45	6.34	4.23
26	216.5	54.12	54.12	5.41	3.61
27	177.3	44.32	44.32	4.43	2.95
28	136.2	34.04	34.04	3.4	2.27
29	93	23.24	23.24	2.32	1.55
30	47.6	11.9	11.9	1.19	0.79
Total					243.79

Furthermore for PPA contracts that pricing is stated as a single, all-in energy price, S&P has developed a separate methodology. For contracts with all-in energy prices S&P first calculates an implied capacity price that is supposed to fund the recovery of the supplier's capital investment. S&P uses the implied capacity price, stated as $/kW, to calculate the implied capacity payment associated with the PPA. The implied capacity payment is found by multiplying the capacity charge, $/kW, by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, S&P adjust the kilowatts under contract to reflect the anticipated capacity that the resource is expected to achieve.

Based on the discussion in this section it can be concluded that no perfect quantitative solution to the problem of PPA-related risk transfer and imputed debt exist. The next section will examine how the issue of Debt Equivalency has been addressed by the Commission.

VI. How Debt Equivalence has been addressed by the Commission?

Utilities have raised the issue of Debt Equivalency in both Cost of Capital and Long-term Procurement proceedings. The Commission long standing position is that cost recovery treatment of Debt Equivalency should be addressed in Cost of Capital proceeding. The Commission has also been considering the issue of Debt Equivalency among other factors in the selection of new supply in Long-term Procurement proceeding. In what follows Commission approach to Debt Equivalency in Long-term Procurement and Cost of Capital proceedings is discussed in more detail.

1. Long-term Procurement Proceeding

Debt Equivalence became an issue in the 2001 long-term procurement proceeding (i.e., a rulemaking proceeding (R.01-10-024) on establishing policies and cost recovery mechanisms for generation procurement and renewable resource development). In that proceeding, SCE requested that the Commission should increase its equity ratio to counter the rating decline that it was expecting to result as it takes on additional power contracts and long term commitments. Although debt equivalence was

addressed in the discussion portion of an interim decision, D.04-01-050, that issue was deferred to the cost of capital proceeding where the energy utilities were expected to present detailed evidence about the treatment of debt equivalence by the rating agencies.

The issue of Debt Equivalency was litigated in the 2004 Long-term Procurement Proceeding (LTPP), R.04-04-003. In that proceeding SDG&E, SCE, and PG&E recommended that Debt Equivalence be adopted in procurement to ensure the resource acquisition process going forward takes into account the impact of Debt Equivalence. PG&E, in particular, had proposed that the impact of Debt Equivalence on the utilities' financial condition should be addressed in the cost of capital proceeding, but that in R.04-04-003 the Commission should establish that the Debt Equivalence impacts of new long-term commitments may be considered in the contract selection and approval process.

In 2004 LTPP decision, D.04-12-048, the Commission recognized that Debt Equivalence is a real economic cost borne by an IOU when it enters into a PPA, and can have an impact on a utility's credit rating. In D.04-12-048 the Commission ruled that Debt Equivalence has to be considered by IOUs and/or independent evaluator in the contract selection and approval process. D.04-12-048 based the methodology for evaluating individual PPAs bids on S&P methodology. However the Commission found the 30% S&P risk factor too high to be reasonable and fair to all PPAs. Therefore the Commission required the utilities to employ a modified S&P methodology of 20% risk factor for all PPA bids.

D.04-12-048 also found that "DE was a subjective factor based on the credit rating agencies' perceived risk associated with PPAs, that the credit agencies ' views are not static and can change with respect to particular PPA during the term of the PPA and that the imputed costs for existing PPA will be reduced as the regulatory climate in California improves."

In 2006 LTPP the Commission eliminated the bid adder for PPAs and the 2006 LTPP decision, D.07-12-052, instructed the utilities to raise the Debt Equivalence issue in Cost of Capital proceedings. More specifically, D.07-12-052 found that the Commission's approach to Debt Equivalence goes against the Commission's stated goal of promoting head-to head competition between PPAs and UOG by creating a disparity between the treatment of PPAs and utility-owned projects in the procurement process.

In response to D.07-12-052, the major utilities filed Petition for Modification (PFM) asking the Commission to revisit its' findings. After deliberation of the competing positions, the Commission ruled it is appropriate in some cases for the IOUs to recognize the effects of Debt Equivalence in their bid evaluation processes. More specifically, it allowed the use of 20% debt equivalence debt equivalence adder in head-to-head competition between PPAs but because of the complexity of the risk-related pros and cons associated with PPA versus UOG ownership it continued to prohibit the use of the debt equivalence adder in solicitations that include both PPA and UOG.

The Commission approach to debt equivalency in LTPP can have significant impact on competitive bids. The Commission has been cognizant of the fact that the inclusion of a debt equivalency adder to competitive bids can preclude new PPAs, despite their desirable consumer benefits such as economic

efficiency, improved reliability, and environmental performance. For example an issue that came up in 2006 LTPP concerns the Renewable Portfolio Standard requirements and the impact of Debt Equivalence on renewables costs. In response, the Commission ruled that it is important to ensure that in head-to-head competition, the use of the Debt Equivalence adder does not disadvantage bids for renewable and innovative low-carbon resources that may have higher capital costs than traditional gas-fired generators.

The Commission approach to Debt Equivalence in Long-term Procurement Proceeding has not changed since D.07-12-052. IOUs are still allowed to use Debt Equivalency adders when evaluating PPA vs. PPA but are instructed not to use Debt Equivalence adders when evaluating PPA vs. UOG.

2. Cost of Capital Proceedings

IOUs raised the issue of Debt Equivalence for the first time in a Cost of Capital proceeding in 1993 (D.92-11-047). In that proceeding, to deal with the impact of Debt Equivalency, utilities requested an adjustment in capital structure by shifting from debt to equity. The Commission rejected utilities request but set a standard for addressing the issue of Debt Equivalency. The Commission recognized that Debt Equivalency may impact utilities' credit rating and cost of borrowing. The Commission stated that the impact of Debt Equivalency should be considered in authorizing capital structure and ROE.

More recently, in compliance with resource procurement decision D.04-01-050 discussed above, IOUs raised the issue of Debt Equivalence in the 2005 Cost of Capital proceeding. In that proceeding SCE, PG&E, and SDG&E recommended that the Commission establish a Debt Equivalence policy to alleviate their concern that Debt Equivalence is an added cost that needs to be considered both in determining an appropriate capital structure and in making resource procurement decisions. Policy recommendations proposed by the utilities included recognition that the Debt Equivalence adversely impacts credit ratings; use of annual ROE proceedings to update and mitigate Debt Equivalence impacts on credit ratings; adoption of S&P's quantitative debt equivalence formula for use in assessing Debt Equivalence costs in power procurement decision-making proceedings.

In addition in the 2005 Cost of Capital proceeding, to mitigate the effects of debt equivalence, SCE proposed to increase its preferred stock ratio and correspondingly reduce its long-term debt ratio by 4 percent. And SDG&E requested to increase its equity with a simultaneous reduction of debt equal to 65% of the debt equivalence for each individual PPA contract approval by the Commission with the cost associated with the capital structure adjustment rolled into the costs of each PPA.

In 2005 Cost of Capital decision, D.04-12-047, the Commission recognized that Debt Equivalency has been reflected in the utilities' credit ratings since at least 1990 and that debt equivalence associated with PPAs can affect utility financial ratios, credit ratings and capital structure. But the Commission declined to adopt a formal debt equivalence policy based on the opinion that the evidence presented in the proceeding did not substantiate a need to consider the Debt Equivalence issue outside of the traditional ROE assessment of risks. The Commission ruled that as part of their annual ROE applications

utilities should include testimony on credit rating and capital structure impacts, including mitigation recommendations of debt equivalence on their PPAs.

Furthermore in D.04-12-047, after assessing the impact of Debt Equivalency on financial ratios that S&P uses to assign credit ratings, the Commission found inclusion of PPA had not adversely impacted utilities' credit ratios or borrowing costs. Nonetheless, the decision approved for SCE a shift from debt to preferred stock arguing that the shift of debt to preferred stock would improve financial metrics, encourage the rating agencies to upgrade SCE's credit status and lower overall long-term costs. But the Commission declined to adopt SDG&E's proposal on the ground that SDG&E had not provided information on the impact of Debt Equivalency on its credit ratings.

Broadly speaking the Commission approach to Debt Equivalency has remained the same as in D.04-12-047. The Commission continues to believe that Debt Equivalence can impact IOUs' credit ratings. In Cost of Capital proceedings the Commission continues to rule that Debt Equivalence should be assessed on a case-by-case basis along with other financial, regulatory and operational risks in setting a balanced capital structure and fair ROE. And in Cost of Capital proceedings the Commission continues to assess the impact of Debt Equivalency on financial ratios that credit rating agencies use to assign credit ratings such as Debt to Total Capital, Funds from Operations to Debt, and Funds from Operations Interest Coverage.

However the strategy of setting a balanced capital structure and fair ROE on case-by-case basis to compensate utilities for the risk of PPAs has been applied differently since 2005 Cost of Capital decision. In what follows, the Commission approach in setting a fair ROE and balanced capital structure in 2006, 2008 and 2012 Cost of Capital decision is first examined. Subsequently the impact of the application of S&P's mitigation methodology on SDG&E's cost of capital and revenue requirement is assessed.

a) Setting a fair ROE in the presence of PPAs

To set an authorized ROE in Cost of Capital proceedings the Commission after considering parties' financial model results, the evidence on market conditions, trends, creditworthiness, interest rate forecasts, additional risk factors, and interest coverage presented by parties, arrives at a base ROE range. Subsequently from the base ROE range found to be just and reasonable, the Commission adopts an authorized ROE. In Cost of Capital proceedings to support major IOUs in California to achieve or maintain investment grade credit ratings, the Commission has been approving an ROE toward the upper end of the ROE range.

In 2006 and 2008 Cost of capital decision the strategy of setting a balanced capital structure and fair ROE on case-by-case basis resulted in increasing the base range of ROE to compensate utilities for the risk of PPAs, in addition to approving an ROE toward the upper end of the ROE range. In contrast in 2012 Cost of capital decision, the approach resulted in choosing an authorized ROE at the top of the ROE range with no additional increases in the base range of ROE.

More specifically in the 2006 Cost of Capital decision, D.05-12-043, , the Commission increased the base range of ROE for SCE, SDG&E, and PG&E by 70 , 50, and 70 basis points, respectively to account for debt equivalence and electric procurement risks. Included in those increased basis points was a premium for perceived regulatory risk in California. In addition for each utility the Commission approved an ROE toward the upper end of the ROE range that was found fair and reasonable.

For example, for PG&E the Commission arrived at a base ROE range of 9.91% to 10.93%. To that range it applied a 70 basis point upward adjustment for electric procurement and regulatory risks resulting in an ROE range of 10.61% to 11.63%. It then adopted a ROE of 11.35% from the upper end of ROE range for test year 2006. Similarly for SCE the Commission arrived at a base ROE range of 9.88% to 10.84%. To that range it applied a 70 basis point upward adjustment for electric procurement and regulatory risks and 28 basis points for inferior credit ratios resulting in an ROE range of 10.86% to 11.82%. It then adopted a ROE of 11.60% from the upper end of ROE range for test year 2006.

Similarly in 2008 Cost of Capital decision, D.07-12-049, to account for debt equivalence and electric procurement risks, the Commission increased the base range of ROE for SCE, SDG&E, and PG&E by 50, 40, and 50 basis points, respectively. The Commission then added 10 basis points premiums to utilities' ROE for regulatory risk as regulatory risk was broken out from Debt Equivalency premium in 2008. In addition for each utility the Commission approved an ROE toward the upper end of the ROE range that was found fair and reasonable.

In contrast in 2013 Cost of Capital Decision, D. 12-12-034, the Commission stated that procurement risk is reflected in the parties' financial modeling results. Therefore the Commission did not increase the base range of ROE to compensate utilities for Debt Equivalency. The Commission considered the utilities credit ratios and how debt equivalency impacts those credit ratios as was done in previous decisions. The Commission also considered cost recovery mechanisms present in California that reduce cost recovery risk such as power procurement commitments, balancing and memorandum accounts and revenue decoupling. To compensate utilities for financial, business, and regulatory risk the Commission authorized an ROE toward the upper end of the ROE range that was found to be fair and reasonable.

The Commission did not grant Debt Equivalency premiums for test year 2013 even though in 2013 Cost of Capital Decision, D. 12-12-034, the Commission acknowledged that there had been an increase in the number of procurement transactions the utilities were entering into.[5] The capital structure and ROE authorized in 2013 decision are effective today. Utilities requested and were granted extensions in 2015, and 2016. Currently utilities have a pending application (A.12-04-015) which if approved will postpone filing of cost of capital applications until 2019.

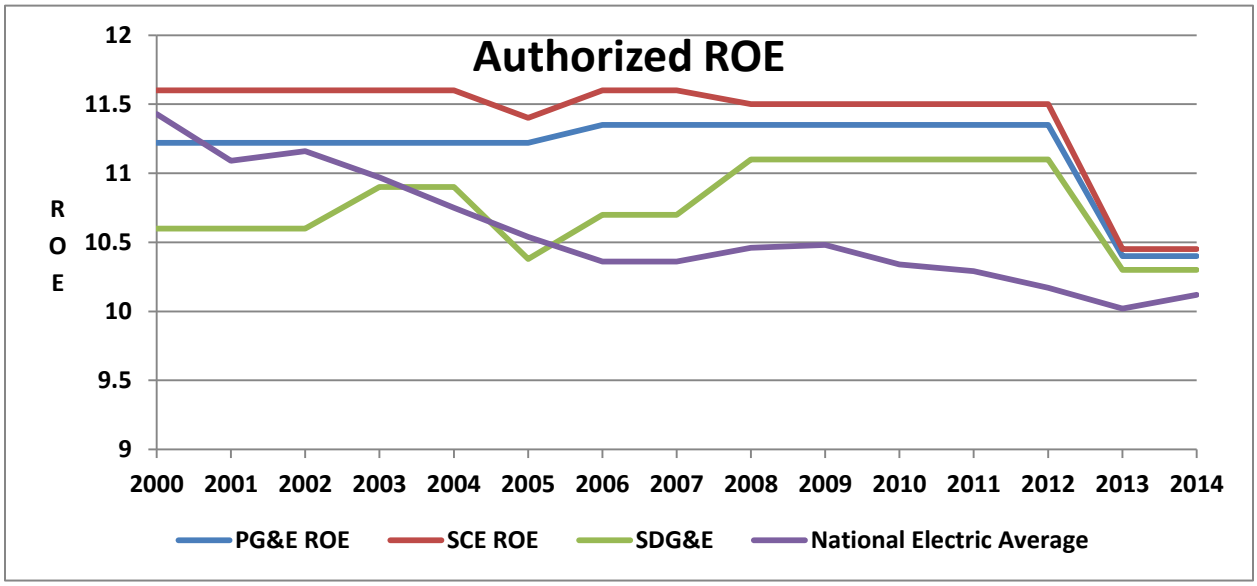
The Debt Equivalency premium that the Commission granted for test year 2006 and 2008 can explain a large part of what has become known as the California Premium. The California premium refers to the

[5] D. 12-12-034, page 33.

finding that the major utilities in California have been earning a return on equity (ROE) higher than the national average. As Figure 4 shows California premium has been more relevant to PG&E and SCE.

An important factor that sets SDG&E apart from the other major utilities in California is the fact that SDG&E has had strong investment grade credit ratings. PG&E and SCE's credit ratings have improved since energy crisis but their credit ratings are still below SDG&E. Therefore SDG&E's authorized ROE quite appropriately has been lower than PG&E and SCE's authorized ROE.

Figure 4



The Debt Equivalency premium granted for test year 2006 and 2008 together covered a 7 year period from 2006 through 2012. Major IOUs in California filed Cost of Capital applications in 2005, 2007 and again in 2012.The Debt Equivalency premium granted for 2006 last through 2007 and the Debt Equivalency premium granted for 2008 lasted through 2012.

Figure 5 contrasts the California premium to the Debt Equivalency premium that the Commission granted for PG&E and SCE. Figure 6 reflects the same contrast for SDG&E. SDG&E's Debt Equivalency premium as Figure 6 shows was lower than SCE and PG&E's Debt Equivalency premium.

As Figure 5 shows for PG&E and SCE the Debt Equivalency premium accounts for close to one-half of their respective California premium. As Figure 6 shows for SDG&E there was no California premium before 2006 and hardly any after 2012. For SDG&E the California premium has been almost entirely due to the Debt Equivalency premium the Commission granted for test year 2006 and 2008.

Figure 5

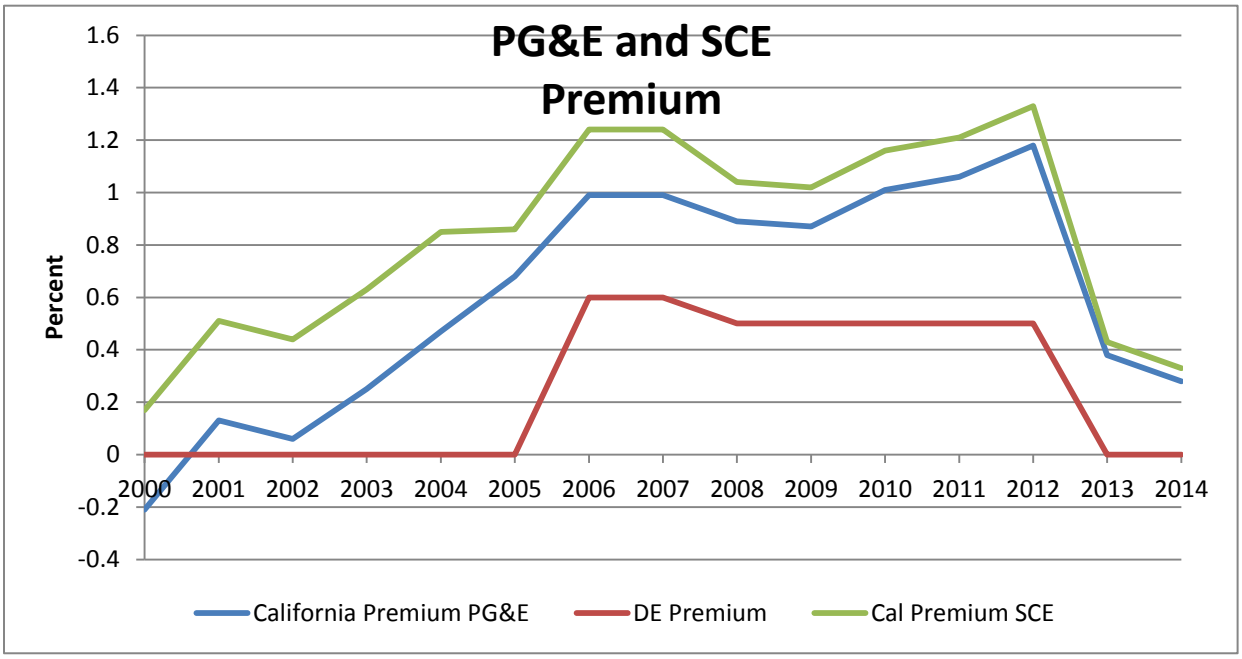
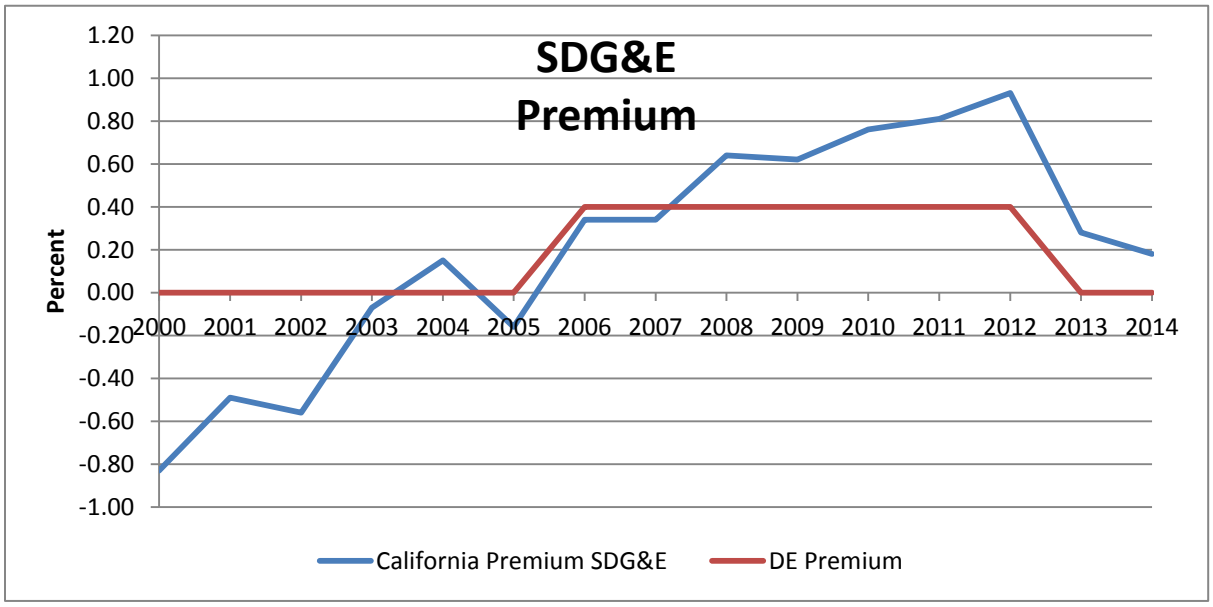


Figure 6



b) Setting a balanced Capital Structure in the presence of PPAs

In addition to proposing adjustments in ROE, SDG&E in 2006 and 2013 Cost of Capital proceeding requested adjustments in capital structure to mitigate the impact of Debt Equivalence. In 2006 Cost of Capital proceeding SDG&E requested a 200 basis points increase in equity ratio with a correspondingly

decrease in debt ratio to mitigate the negative effects of debt equivalence. And in 2013 Cost of Capital proceeding SDG&E requested a 300 basis points increase in common equity ratio and a corresponding decrease in preferred stock ratio to mitigate the impact of its' existing, and pending PPAs.[6]

In 2006 Cost of Capital decision, D.05-12-043, the Commission found that SDG&E's credit status and credit ratings do not substantiate a need to mitigate debt equivalence through a change in its authorized capital structure. In contrast in 2012 Cost of Capital decision, D. 12-12-034, the Commission granted SDG&E's request to adjust its' capital structure. However, in granting SDG&E's request the Commission reaffirmed its long standing position of not adopting S&E methodology by restating the disagreement among credit rating agencies in regard to PPAs but stated that the common equity ratio SDG&E is seeking is reasonable because it is similar to SDG&E's ratemaking common equity ratio.[7] In fact in D. 12-12-034 the Commission also granted SoCalGas' request to increase its common equity ratio by 400 basis points based on a similar reasoning.

The Commission by increasing SDG&E and SoCalGas' equity ratio to 52 percent brought their equity ratios more in line with the average equity ratio of utilities nationwide. According to the Regulatory Research Associates, the average equity ratio of utilities in the nation has been on an upward trajectory, increasing from slightly higher than 40 percent for electric utilities and 35 percent for gas utilities in 1980 to slightly over 50 percent in 2014.[8] The increase in the average equity ratio explains why despite a sharp decline in return on equity (ROE) nationwide during the same period (from around 14 percent in 1980 or 16 percent in 1982 to around 8 percent in 2014 for electric utilities), the decline in rate of return (ROR) has been more modest (from around 10 percent in 1980 or 12 percent in 1982 to around 8 percent in 2014 for electric utilities).[9]

Table 12 shows SDG&E's 2013 authorized capital structure, and authorized rate of return (ROR). In Table 12 authorized rate of return is 7.79%.

Table 12

	Ratio	Cost	WACC
Debt	45.25	5.00	2.26
Preferred Stock	2.75	6.22	0.17
Common Equity	52.00	10.30	5.36
Totals	100		7.79

[6] SDG&E's hearing exhibit demonstrated that Standard & Poor's (S&P) had imputed debt equivalence into SDG&E's long-term debt. SDG&E was expecting S&P to increase imputed debt equivalence into its long-term debt partly due to SDG&E's pending purchase power tolling agreements.
[7] The ratemaking capital structure is different from recorded capital structure in that it includes the impact of ratemaking adjustments.
[8] "Regulatory Issues Overview RRA Presentation to NARUC's Gas Committee," SNL Energy, July 13, 2015.
[9] Ibid.

To find the impact of the adjustment in capital structure granted in D. 12-12-034, in Table 13, rate of return is calculated using SDG&E's 2012 authorized capital structure and 2013 adopted cost of debt, preferred and common stock. In Table 13 rate of return WACC is 7.67%.

Table 13

	Ratio	Cost	WACC
Debt	45.25	5.00	2.26
Preferred Stock	5.75	6.22	0.36
Common Equity	49.00	10.30	5.05
Totals	100		7.67

Comparison of Table 12 to Table 13 shows that the adjustment in the authorized capital structure increased SDG&E's rate of return (ROR) by 12 basis points (7.79%-7.67%). Using SDG&E's rate base in 2013, $4137 million,[10] the adjustment in the authorized capital structure resulted in an increase in revenue requirement of around $4.96 million, ((7.79%-7.67%)*4137 = $4.96).[11] The change in authorized capital structure was approximately equivalent to 25 basis points increase in ROE.

Next S&P's mitigation methodology, discussed in earlier sections, will be applied to find the impact of the application of S&P's mitigation method on SDG&E's cost of capital (rate of return) and revenue requirement.

c) Application of S&P's Mitigation Methodology

To investigate the impact of the application of S&P methodology on SDG&E's cost of capital and revenue requirement in what follows S&P's Mitigation Method 1 which calls for increasing the amount of equity in the rate base will be applied first. Subsequently S&P's Mitigation Method 2 which calls for increasing ROE is applied.

The impact of S&P's mitigation methods on cost of capital and revenue requirement can be contrasted to the impact of the adjustments the Commission approved for SDG&E that were discussed in the previous sections.

d) Adjustment to authorized capital structure

Table 14 shows the impact of Debt Equivalency that S&P had imputed and was expected to impute due to SDG&E's pending purchasing power tolling agreements on capital structure. In Table 14, SDG&E's total capital, $8471,[12] and authorized capital ratios in 2012 are used to estimate 2012 capital structure. SDG&E's authorized capital structure in 2012 had more preferred stocks and less debt than SDG&E's

[10] SDG&E's witness, Jesse S. Aragon, testimony in SDG&E's 2016 GRC, page 5.
[11] The figure does not include the required increase in taxes.
[12] SDG&E's witness, Sandra K. Hrna, testimony in 2013 Cost of Capital proceeding, page 6.

recorded capital structure.[13] The impact of Debt Equivalency of the existing and pending PPAs, as Table 14 shows, was to increase the level of debt from approximately 45 to 55 percent.

Table 14

	2012 Authorized Capital Structure %	Estimated 2012 Capital Structure ($)	S&P Imputed	Expected Debt Equivalence	Imputed Capital $	Adjusted Capital %	Change In Capital %
Debt	45.25	3833.13	182	1578	5593.13	54.67	9.42
Preferred Stock	5.75	487.08			487.08	4.76	-0.99
Common Equity	49.00	4150.79			4150.79	40.57	-8.43
Totals	100	8471	182	1578	10231	100	

Source: SDG&E's 2013 Cost of Capital testimony.

To restore the original capital structure, SDG&E had to issue new common stocks and recall outstanding debt. Table 15 shows the capital structure after the mitigation effort with the imputed debt.

Table 15

	Amount ($)	%
Debt	4629.53	45.25
Preferred Stock	588.28	5.75
Common Equity	5013.19	49.00
Totals	10231.00	100

Table 16 shows SDG&E's capital structure and cost of capital post-PPA contract excluding the imputed debt. As Table 16 shows the mitigation effort increases the percentage of more expensive types of capital, common stocks, and reduces the percentage of less expensive type of capital, debt. Common equity increases from 49 percent to 59 percent. Debt decreases from 45 percent to 35 percent.

Table 16

	Amount ($)	%	Cost	WACC
Debt	2970.73	35.07	5.00	1.75
Preferred Stock	487.08	5.75	6.22	0.36
Common Equity	5013.19	59.18	10.30	6.10
Totals	8471.00	100		8.21

[13] The recorded capital structure is different from ratemaking capital structure in that it does not include the impact of ratemaking adjustments.

Comparison of Table 16 to Table 13 demonstrates that the mitigation effort increases revenue requirement by $22.34 million,[14] which is the difference between the pre-PPA and post-PPA cost of capital times rate base, $4137, ((8.21%-7.67%)*4137 = $22.34 million).

e) Adjustments to ROE

In Table 3 the pre-PPA contract cost of capital (WACC) is 7.67%. To restore the weighted average cost of capital (WACC) with imputed debt included in capital structure, as Table 17 demonstrates, the allowed return on equity has to increase from 10.30 percent to 11.44 percent.

Table 17
Adjusted Capital Structure Reflecting Imputed Debt and Constant WACC

	Amount ($)	%	Cost	WACC
Debt	5593.13	54.67	5.00	2.73
Preferred Stock	487.08	4.76	6.22	0.30
Common Equity	4150.79	40.57	11.44	4.64
Totals	10231			7.67

Table 18 shows SDG&E's cost of capital after the increase in return on equity without the imputed debt. As Table 18 shows, this method of mitigation increases cost of capital (from 7.67% to 8.22%) post-PPA contract.

Table 18
Capital Structure without Imputed Debt at Higher ROE

	%	Cost	WACC
Debt	45.25	5.00	2.26
Preferred Stock	5.75	6.22	0.36
Common Equity	49.00	11.44	5.60
Totals	100		8.22

The impact on cost of capital and revenue requirement is similar to the adjustment in capital structure. The increase in revenue requirement is approximately $22.75 million, excluding the required increase in taxes.

The two mitigation methods result in much higher increases in revenue requirement than what the Commission approved. The increase in equity ratio from the application of Method One is 10 percent (from 49% to 59%) and the increase in return on equity from the application of Method Two is 1.14%

[14] The figure does not include the required increase in taxes.

(from 10.30% to 11.44%). The increase in revenue requirement from the application of either method is approximately $22.5 million.

As was discussed before in 2012, the Commission approved a 3 percent increase in equity ratio for SDG&E, which was equivalent to 25 basis increase in return on equity. In addition to compensate utilities for financial, business, and regulatory risk the Commission authorized an ROE toward the upper end of the ROE range that was found to be fair and reasonable. For SDG&E, the Commission arrived at a base ROE range of 9.60% to 10.40%. The Commission then set the test year 2013 ROE at 10.30%, which is 30 basis points higher than the midpoint of the range. Therefore, the two adjustments were equivalent to an increase in return on equity of about 55 basis points. The increase in revenue requirement resulting from the two adjustments was approximately $11 million, excluding the required increase in taxes.

VII. Conclusion

The Commission's long standing position is that the impact of Debt Equivalency on utilities' financial condition should be addressed in Cost of Capital proceeding. In addition in Long-term Procurement proceedings the Commission has been considering the Debt Equivalency impact of new long-term commitments in the contract selection and approval process in some cases.

The Commission preference to address Debt Equivalence in Cost of Capital proceeding appears to be cost effective. Obviously mitigation cost, first and for most, depends on the extent of mitigation. When S&P's mitigation methodology is applied, as was shown in the example above, the mitigation cost is the highest when it is addressed in Long-term Procurement proceeding.

In Cost of Capital proceedings the Commission has acknowledge that rating agencies impute debt from long-term PPAs and incorporate that in their credit analysis. But the Commission has not adopted a comprehensive policy on the cost recovery treatment of Debt Equivalency.

The Commission's approach in Cost of Capital proceedings is partly based on the understanding that S&P always imputes debt but Fitch and Moody's sometimes do not and that S&P methodology should not be over-weighted versus Moody's and Fitch approach. Moody's, in particular, conducts qualitative assessment of PPA risk. Moody's determine the degree to which PPA effect a company's financial flexibility by a qualitative assessment of the inherent risk. Similarly Fitch does not always assign Debt Equivalency to PPA. More specifically Fitch does not assign Debt Equivalency when there is a high probability of cost recovery.

In Cost of Capital proceedings, the Commission has ruled that Debt Equivalence should be assessed on a case-by-case basis along with other financial, business and regulatory risks in setting a balanced capital structure and fair ROE. In addition in Cost of Capital proceedings the Commission continues to assess the impact of Debt Equivalency on financial ratios that rating agencies use to assign credit ratings.

The Commission has applied the strategy of setting a balanced capital structure and fair ROE on case-by-case basis differently over the years. In 2006 and 2008 Cost of capital decision to compensate utilities for the risk of PPAs the Commission granted Debt Equivalency premiums to utilities. The Debt Equivalency premiums that the Commission granted for test year 2006 and 2008 explains a large part of what has become known as California premium.

In 2013 Cost of Capital decision the Commission did not grant Debt Equivalency premiums to utilities. Utilities have not filed Cost of Capital applications since 2012. California premium was contracted in 2013 and has remained low.