

Decision 19-12-056 December 19, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2020 and to Partially Reset the Annual Cost of Capital Adjustment Mechanism.

Application 19-04-014

And Related Matters.

Application 19-04-015

Application 19-04-017

Application 19-04-018

**DECISION ON TEST YEAR 2020 COST OF CAPITAL
FOR THE MAJOR ENERGY UTILITIES**

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**DECISION ON TEST YEAR 2020 COST OF CAPITAL
FOR THE MAJOR ENERGY UTILITIES**

Summary

This decision establishes the 2020 ratemaking cost of capital for Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E) San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas).

The test year 2020 authorized capital structures for the four applicants are as follows.

	SCE	PG&E	SDG&E	SoCalGas
Long-term debt	43.00%	47.50%	45.25%	45.60%
Preferred equity	5.00%	0.50%	2.75%	2.40%
Common equity	52.00%	52.00%	52.00%	52.00%
Total	100.00%	100.00%	100.00%	100.00%

The test year 2020 authorized costs of long-term debt, costs of common equity, costs of preferred equity, and authorized rates of return are as follows.

	SCE	PG&E	SDG&E	SoCalGas
Cost of long-term debt	4.74%	5.16%	4.59%	4.23%
Cost of preferred equity	5.70%	5.52%	6.22%	6.00%
Cost of common equity	10.30%	10.25%	10.20%	10.05%
Rate of Return	7.68%	7.81%	7.55%	7.30%

SDG&E did not propose a cost of preferred equity in this proceeding, and it is directed to propose an updated cost of preferred equity within 30 days of the effective date of this decision through a Tier 2 Advice Letter submitted to the Commission's Energy Division.

This decision also continues the previously authorized cost of capital mechanism through the 2020 test year cycle.

These proceedings are closed.

1. Jurisdiction and Background

The applicants are public utilities subject to the jurisdiction of California Public Utilities Commission (Commission) as defined in Section 218 of the Public Utilities Code. Southern California Edison (SCE), a California corporation and wholly owned subsidiary of Edison International, provides electric service principally in southern California. Pacific Gas and Electric Company (PG&E), a California corporation, provides electric and gas services in northern and central California. San Diego Gas & Electric Company (SDG&E), a California corporation wholly owned by Sempra Energy, provides electric service in a portion of Orange County and electric and gas services in San Diego County. Southern California Gas Company (SoCalGas), a California corporation wholly owned by Sempra Energy, provides gas services throughout Central and Southern California from Visalia to the Mexican border.

All four applicants filed their respective applications with the Commission on April 22, 2019. On May 22, 2019, the California Choice Energy Authority filed and served a response. On May 23, 2019, the Utility Consumers' Action Network (UCAN) filed a protest. On May 24, 2019, the Public Advocates Office of the California Public Utilities Commission (Cal Advocates), Energy Producers and Users Association (EPUC), Indicated Shippers (IS), Environmental Defense Fund (EDF), The Utility Reform Network (TURN), the City and County of San Francisco, and the County of San Diego filed protests. Also on May 24, 2019, Institutional Equity Investors (IEI), East Bay Community Energy, City of San Jose, Peninsula Clean Energy Authority jointly, and Clean Power Alliance of

Southern California filed responses. On June 2, 2019 the applicants all filed replies to the responses and protests.

A prehearing conference was held in Sacramento, California on June 17, 2019 where parties discussed the scope of the proceedings, consolidation, schedule, and the need for hearings. Six days of evidentiary hearings were held in San Francisco, California between September 3, 2019 through September 10, 2019.

Assembly Bill (AB) 1054¹ was signed by Governor Newsom on July 12, 2019, and as noted by EDF in its motion, also on July 12, 2019, this new law impacts the issues scoped into this proceeding. The applicants were directed by Administrative Law Judge (ALJ) ruling on July 15, 2019 to supplement the record with additional testimony that provided detail regarding how AB 1054 transforms the risks discussed in the applicants' testimony and how this new law impacts all other issues scoped into this proceeding. All four applicants complied with this ruling.

Opening briefs were filed on September 30, 2019 by the applicants, TURN, EDF, Thomas R. Del Monte (Del Monte), Cal Advocates, EPUC/IS, UCAN and Protect Our Communities Foundation (POC), IEI, and the Federal Executive Agencies (FEA). Reply Briefs were filed on October 10, 2019 by the applicants, TURN, Del Monte, Cal Advocates, EPUC/IS, IEI, UCAN/POC and FEA.

2. Issues Before the Commission

This proceeding addresses SCE, PG&E, SDG&E, and SoCalGas's test year 2020 cost of capital. Issues impacting these four utilities' test year 2020 costs of capital are:

¹ Stats. 2019, ch. 81.

- The appropriate capital structure;
- The appropriate cost of long term debt;
- The appropriate cost of preferred equity;
- The appropriate cost of common equity;
- Additional risk factors, including financial, business, and regulatory risks, that should be considered in setting the utilities' authorized return on equity (ROE);
- The appropriate rate of return on the utility rate base;
- The appropriateness of continuing the cost of capital mechanism as established in Decision (D.) 08-05-035 and modified by subsequent Commission Decisions;
- Modifications to the cost of capital mechanism;
- Whether the applicants complied with D.17-07-005;
- Whether PG&E's proposed treatment of customer deposits should be approved or modified; and
- Whether PG&E should be ordered to file a new cost of capital application when it emerges from Chapter 11 bankruptcy.

The Commission will not consider a separate wildfire adder in the scope of this proceeding. Risks of all kind are addressed in this proceeding; a separate adder is not appropriate for one risk.

Additionally, this decision does not address the issue of whether there should be a blended ROE for the gas and electric assets of the combined service utilities. The Commission may address this potential policy modification in a future proceeding. Authorizing a blended ROE for the combined service utilities could result in a significantly modified impact on the financials of the companies. The Commission needs to build a stronger record to determine this impact before authorizing a blended ROE for the combined service utilities.

3. Capital Structure

The capital structure of an investor owned utility (IOU) is the proportional authorization of shareholders' equity and debt that comprise a company's long-range financing or its capitalization. For the purposes of this proceeding, the capital structures of the applicants are comprised of distributions of long-term debt, preferred equity, and common equity.² Because the level of financial risk that the utilities face is determined in part by the proportion of their debt to permanent capital, or leverage, we must ensure that the utilities' adopted equity ratios are sufficient to maintain reasonable credit ratings and attract capital while also ensuring there are adequate ratepayer protections regarding the costs of the components of capitalization.

3.1. SCE

SCE seeks a test year 2020 ratemaking capital structure of 43.00% long-term debt, 5.00% preferred equity, and 52.00% common equity. SCE's current authorization is 43.00% long-term debt, 9.00% preferred equity, and 48.00% common equity. In January 2019, Standard and Poor's (S&P) modified SCE's credit rating from BBB+ to BBB and in March 2019 Moody's modified SCE's credit rating from A3 to Baa2. SCE's credit rating is considered investment grade.³

SCE notes that "[t]he record evidence clearly shows that SCE's 9.00% level of preferred equity makes it an extreme outlier. It is substantially higher than the

² Debt due within one year, short-term debt, is excluded.

³ S&P has four investment grade levels, the lowest level is medium grade (BBB-, BBB, and BBB+ ratings), upper grade (A-, A, and A+), high grade (AA-, AA, and AA+), and highest grade of AAA.

1.0 to 2.75 percent levels currently authorized for the other California electric utilities.”⁴

FEA agrees with SCE that its common equity should be increased to 52.00%, however it asserts that SCE should have no authorization for preferred equity and the remainder of its capital structure, 48.00%, should solely be authorized as long-term debt.

TURN notes that increasing common equity while reducing the preferred equity authorization increases costs to ratepayers because common equity is more expensive than preferred equity. TURN indicates that a common equity proportion of 50.00% for SCE would balance the utility’s interest in lower leverage for credit rating purposes with the ratepayer interest in lower cost of capital. TURN notes a 50.00% common equity proportion would still support an investment grade rating for the utility.

Cal Advocates notes that “[t]he common equity ratio increase requested by SCE has not been justified with any specific quantification of the value of the alleged benefits. Furthermore, the increase is unlikely to have economic benefit to ratepayers because Edison International has a consolidated capital structure containing only about 38.00% common equity.”⁵ Cal Advocates recommends that the Commission allow SCE to reduce its authorization for preferred equity but rather replace it with an increased long-term debt authorization rather than a common equity authorization.

We agree that the Commission needs to ensure that the capital structures employed by the IOUs are balancing the need for a proper level of leverage to ensure credit worthiness while also ensuring that the ratepayers are only

⁴ Exhibit SCE-01 at 61 and 87-88.

⁵ Cal Advocates Opening Brief at 32.

exposed to reasonable costs. An authorization of 52% common equity is reasonable. SCE's common equity authorization request of 52% is near the upper threshold of what is considered reasonable as compared to national authorizations. Additionally, a capital structure consisting of 43.00% long-term debt and 5.00% preferred equity is reasonable.

SCE's request for an increased authorization for common equity is not unprecedented in California and is in-line with what the other applicants' authorizations have been in recent years. Further, its overall requested capital structure balances long-term debt, preferred equity, and common equity well.

We find that SCE's requested capital structure is reasonable, and we adopt the requested modification.

3.2. PG&E

PG&E seeks a test year 2020 ratemaking capital structure of 47.50% long-term debt, 0.50% preferred equity, and 52.00% common equity. PG&E's current authorization is 47.00% long-term debt, 1.00% preferred equity, and 52.00% common equity. Currently PG&E is a non-dividend paying company with a D credit rating, meaning it is in default on its bond payments.⁶ PG&E's credit rating is not considered investment grade.

No party contested PG&E's proposed capital structure. Further, the adjustments are minor and not outside the limit of reasonableness. The ratepayer impact of modifying PG&E's authorization for preferred equity down by 0.50% and its long-term debt authorization up 0.50% is minimal.

We find PG&E's requested capital structure reasonable, and we will adopt it.

⁶ Exhibit PGE-01 at 2-8.

3.3. SDG&E

SDG&E seeks a test year 2020 ratemaking capital structure of 44.00% long-term debt, 0.00% preferred equity, and 56.00% common equity. SDG&E's current authorization is 45.25% long-term debt, 2.75% preferred equity, and 52.00% common equity. Since late 2018, SDG&E's credit rating has been modified from A2 to Baa1 by Moody's and A to BBB+ by S&P.⁷ SDG&E's credit rating is considered investment grade.

SDG&E explains its perspective on the issue of the complexity in setting the appropriate capital structure. "A debt ratio that is too low fails to take advantage of a tax-deductible source of financing that is lower-cost than equity. However, a debt ratio that is too high (with an equity ratio that is too low) increases the risk of debt repayment to lenders, which could result in higher costs of capital over the long-term. Both scenarios can negatively impact ratepayers."⁸

SDG&E indicates "that this change in its capital structure is necessary to reflect SDG&E's actual (recorded) capital structure since 2013, to facilitate SDG&E's management of its financial risks, and to improve its credit ratings."⁹ SDG&E notes that it has not issued preferred equity since 1993 and redeemed all issued and outstanding shares of its preferred equity in 2013.¹⁰ SDG&E states that this is the case because the cost of preferred equity has increased relative to the cost of long-term debt and the market preference for preferred equity has decreased in recent times. SDG&E also notes that "[p]referred equity is a source

⁷ Exhibit SDG&E-01 at BAF-7.

⁸ SDG&E Opening Brief at 76.

⁹ SDG&E Opening Brief at 76.

¹⁰ Exhibit SDG&E-02 at MM-6.

of capital that [is] issued in shares, like common equity, but comes with preferential treatment for dividends.”¹¹

SDG&E argues “for SDG&E to return to a strong single ‘A’ bond rating, it must maintain a debt ratio in the range of 35 percent – 45 percent. This is consistent with SDG&E’s actual/proposed debt ratio of 44 percent (with an equity ratio of 56 percent).”¹²

FEA counters with testimony that indicates that a 56% common equity ratio is excessive and unwarranted relative to national averages.¹³

UCAN/POC presents calculations that indicate that of 47 pending rate cases nationally, only four utility applications request a common-equity ratio of 56% or more; SDG&E is one of the four cases with a 56% common-equity request.¹⁴ UCAN/POC additionally presents calculations that indicate that SDG&E’s currently approved common-equity ratio of 52% is still larger than 70.5% of all authorized common-equity ratios from the time period of 2017 through July 2019.¹⁵

SDG&E indicates that it must have a 56% equity ratio to ensure it is leveraged properly to be eligible for an “A” credit rating but makes this claim while also requesting that we eliminate its more affordable preferred equity authorization. SDG&E fails to suggest it could maintain its proposed leverage through the authorization of preferred equity. Preferred equity has qualities of both debt and equity financing and is treated by credit rating agencies as a

¹¹ Exhibit SDG&E-02 at MM-3.

¹² Exhibit SDG&E-02 at MM-10.

¹³ Exhibit FEA-01 at 22.

¹⁴ Exhibit UCAN/POC-15.

¹⁵ Exhibit UCAN/POC-15.

hybrid of debt and equity.¹⁶ Instead, SDG&E seeks to increase its authorization of common equity to 56%, an unprecedented level for California, rather than utilize a blend of long-term debt, preferred equity, and common equity.

SDG&E suggests it is the policy of the Commission to match the capital structure authorization to the actual recorded capital structure of the IOU.¹⁷ Rather, it is the policy of the Commission for the authorization of an IOU's capital structure to be in the public interest of the ratepayers of California.

SDG&E's requested modification of its capital structure is denied. It is unreasonable for SDG&E to request an elimination of its authorization for preferred equity while simultaneously indicating that it must have an authorization for common equity to maintain its desired level of credit support. Because SDG&E is not requesting a significant increase in long-term debt, this decision will authorize no modification. SDG&E shall maintain its current authorization of 45.25% long-term debt, 2.75% preferred equity, and 52.00% common equity.

3.4. SoCalGas

SoCalGas seeks a test year 2020 ratemaking capital structure of 43.60% long-term debt, 0.40% preferred equity, and 56.00% common equity. SoCalGas's current authorization is 45.60% long-term debt, 2.40% preferred equity, and 52.00% common equity. SoCalGas's current credit rating is A from S&P and A1 from Moody's.¹⁸

¹⁶ Exhibit SDG&E-02 at MM-3.

¹⁷ Exhibit SDG&E-02 at MM-4.

¹⁸ Exhibit SCG-05 at 12.

SoCalGas notes that “[w]hile the lower cost of debt relative to equity may be viewed as a way to lower a utility’s cost of capital by having the utility issue more debt rather than equity, this can increase the financial risk to the utility, which ultimately can adversely impact ratepayers.”¹⁹

SoCalGas echoes SDG&E’s argument that “for a single “A” credit rating (which is optimal and cost efficient for ratepayers), the debt ratio range is 35.00% - 45.00%, implying a common equity ratio range of 55.00% - 65.00% (for a company like SoCalGas with little-to-no preferred equity).”²⁰

The record does not substantiate SoCalGas’s argument that to maintain its single A credit rating it must have a debt ratio in the range of 35-45% and that to meet that ratio, common equity is the only option. As it notes, it is a company that has chosen to issue little-to-no preferred equity, however because it has chosen not to issue preferred equity does not mean it must have the remainder of its capital structure fulfilled with common equity.

An authorization of 56% common equity is not reasonable. SoCalGas’s current common equity authorization of 52% is near the upper threshold of what is considered reasonable as compared to national authorizations. SoCalGas’s requested modification of its capital structure is denied. SoCalGas shall maintain its existing authorization of 45.60% long-term debt, 2.40% preferred equity, and 52.00% common equity.

4. Long-Term Debt and Preferred Equity Costs

Long-term debt and preferred equity costs are based on actual, or embedded, costs. Future interest rates must be anticipated to reflect projected

¹⁹ SoCalGas Opening Brief at 44.

²⁰ Exhibit SCG-02 at 10.

changes in a utility's cost caused by the issuance and retirement of long-term debt and preferred equity during the year.

We recognize that actual interest rates do vary and that our task is to determine "reasonable" debt cost rather than actual cost based on an arbitrary selection of a past figure.²¹ Consistent with past practice, we conclude that the latest available interest rate forecast should be used to determine embedded debt cost in cost of capital proceedings.

4.1. SCE

SCE's proposed 2020 cost of long-term debt is 4.74% and its 2020 cost of preferred equity is 5.70%. No party contested SCE's proposed cost of long-term debt and cost of preferred equity; additionally, the active parties stipulated to these numbers in the filing of joint stipulated facts on August 29, 2019.

SCE's proposed 2020 cost of long-term debt and cost of preferred equity is reasonable, and the Commission adopts these proposals.

4.2. PG&E

PG&E's proposed 2020 cost of long-term debt is 5.16% and its 2020 cost of preferred equity is 5.52%. PG&E notes that these proposals are uncontested.

Except for debtor-in-possession (DIP) financing, PG&E indicated it is not able to issue new debt or equity while in bankruptcy and will rely on its cash from operations and proceeds of its DIP facilities in place of the long-term debt that it otherwise would have raised in conventional capital markets.

PG&E additionally notes that its cost of long-term debt for cost of capital purposes may be different with its exit financing for its emergence from Chapter 11 bankruptcy. To account for this possible difference, PG&E proposes

²¹ 38 CPUC2d (1990) 233 at 242 and 243.

to update its cost of debt for cost of capital purposes, for the period beginning after it emerges from bankruptcy to incorporate the costs of its exit financing, and the appropriate forward-looking forecast of debt costs for the remaining forecast period.

The active parties stipulated to PG&E's proposed cost of preferred equity in the filing of joint stipulated facts on August 29, 2019. No party contested PG&E's proposal for the treatment of its 2020 cost of long-term debt and cost of preferred equity.

The Commission finds PG&E's proposals are reasonable and adopts them.

4.3. SDG&E

SDG&E's proposed 2020 cost of long-term debt is 4.59%. This is SDG&E's currently authorized cost of long-term debt, and it is seeking no change. No party contested SDG&E's proposed cost of long-term debt; additionally, the active parties stipulated to this number in the filing of joint stipulated facts on August 29, 2019.

SDG&E's proposed 2020 cost of long-term debt is reasonable, and the Commission adopts its proposal.

SDG&E did not propose a 2020 cost of preferred equity. It notes that "SDG&E redeemed all issued and outstanding shares of its preferred equity in 2013 and does not anticipate issuing any preferred equity in the foreseeable future, as reflected in its actual capital structure."²² However, today's adopted capital structure provides for the authorization of preferred equity. For cost recovery purposes, SDG&E's current authorization of 6.22%²³ remains in place.

²² Exhibit SDG&E-02 at 17.

²³ D.17-07-005.

However, SDG&E shall submit a Tier 2 advice letter to the Commission's Energy Division no later than 30 days following the effective date of this decision that includes an updated proposal for its cost of preferred equity. SDG&E shall adhere to the same methodology for the development of its proposed cost of preferred equity that the other applicants in this proceeding used.

4.4. SoCalGas

SoCalGas's proposed 2020 cost of long-term debt is 4.23% and its 2020 cost of preferred equity is 6.00%. No party contested SoCalGas's proposed cost of long-term debt and cost of preferred equity; additionally, the active parties stipulated to these numbers in the filing of joint stipulated facts on August 29, 2019.

SoCalGas's proposed 2020 cost of long-term debt and cost of preferred equity is reasonable, and the Commission adopts these proposals.

5. Return on Common Equity

The legal standard for setting the fair rate of return has been established by the United States Supreme Court in the Bluefield and Hope cases.²⁴ The Bluefield decision states that a public utility is entitled to earn a return upon the value of its property employed for the convenience of the public and sets forth parameters to assess a reasonable return.²⁵ Such return should be equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings attended by

²⁴ The Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Water Works & Improvement Company v. Public Service Commission of the State of Virginia, 262 U.S. 679 (1923).

²⁵ Hope held that the value of a utility's property could be calculated based on the amount of prudent investment minus depreciation.

corresponding risks and uncertainties. That return should also be reasonably sufficient to ensure confidence in the financial soundness of the utility, and adequate, under efficient management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties.

The Hope decision reinforces the Bluefield decision and emphasizes that such returns should be sufficient to cover capital costs of the business. The capital cost of business includes debt service and equity dividends. The return should also be commensurate with returns available on alternative investments of comparable risks. However, in applying these parameters, we must not lose sight of our duty to utility ratepayers to protect them from unreasonable risks including risks of imprudent management.

We attempt to set the ROE at a level of return commensurate with market returns on investments having corresponding risks and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility service obligation. To accomplish this objective, we have consistently evaluated analytical financial models as a starting point to arrive at a fair ROE.

5.1. Proxy Groups

In evaluating the ROE for similar companies, the Commission has historically held that three specific screens should be employed when selecting a comparable proxy group. Those screens are: (1) to exclude companies that do not have investment grade credit ratings; (2) to exclude companies that do not have a history of paying dividends; and, (3) to exclude companies undergoing a restructure or merger. Additional screens are acceptable to the extent that adequate justification is provided.

A proxy, by common definition, is a substitute. Hence, companies selected as a proxy group of a utility should have characteristics similar to that utility. In order to ensure comparability and reasonableness of financial modeling results, the utilities and companies selected in the proxy group should be exposed to similar risks.

Historically, the applicants have presented a more traditional group of proxy companies for Commission consideration, all a derivative of the Value Line electric and gas utility survey. In this consolidated proceeding, the proposed proxy groups of the applicants are more dissimilar from each other and represent a wide range of assertions for which other companies would be appropriate for comparison.

SCE proposes a proxy group that includes electric and water and natural gas utilities; SCE asserts this is because gas and water utilities are highly regulated and provide insights into the cost of equity for state-regulated utilities.²⁶

PG&E proposes several different proxy groups, including a “non-regulated” industry group and a regulated utility group that included some utilities that are undergoing a restructure or merger.²⁷ PG&E asserts this is appropriate because it is not currently considered investment grade and is not paying dividends. PG&E’s witness included “market data for companies in capital intensive, network industries (CINI), and provided ROE estimates for subsets of the CINI Sample: regulated electric utilities; regulated water and gas

²⁶ Exhibit SCE-02 at 37.

²⁷ Exhibit EPUC/IS/TURN-01 at VI-38:13 to VI-40:15

local distribution utilities; non-electric utilities; and, a non-regulated group of CINI companies.”²⁸

SDG&E used a group of investment-grade dividend-paying combination gas and electric utilities covered in Value Line’s Electric Utility industry group. SDG&E started with a group of 29 comparable utilities.²⁹ SDG&E ran several screens to remove companies that it asserts have dissimilar risk profiles. For instance, Avista Group was excluded because of the ongoing sale of a major hydro asset. Other companies were excluded due to ongoing mergers or nuclear exposure. The final proxy group that SDG&E recommends contains 17 utilities that it asserts have a comparable risk profile.

SoCalGas employed two proxy groups. SoCalGas examined a group of investment-grade dividend-paying natural gas utilities contained in Value Line’s natural gas distribution utility group.³⁰ SoCalGas also examined a group of four investment-grade dividend-paying combination gas and electric utilities covered in Value Line’s Electric Utility industry group; SoCalGas asserts that these companies possess similar assets to SoCalGas.

With the exception of Unitil Corp, FEA chose, in its analysis, to follow the same comparable companies presented by the IOU witnesses in their respective testimony.³¹

EPUC/IS raised significant issue with the methodologies employed by the applicants in selecting proposed proxy groups. Regarding SCE and PG&E, EPUC/IS assert the following issues, for both utilities³²:

²⁸ PG&E Opening Brief at 19.

²⁹ Exhibit SDG&E-04 at 25.

³⁰ Exhibit SCG-04 at 26.

³¹ FEA Opening Brief at 8.

- Attempting to rely on the use of a proxy group comprising CINI companies; the Commission historically has roundly rejected this approach;
- Including companies in their utility proxy groups that are involved in a merger or acquisition; again, the Commission has made clear that these companies should be excluded from proxy groups;
- Including companies that are not included in the Value Line Investment Survey universe of utility stocks; the Commission's historical ground rules for proxy groups requires is that proxy companies must have investment grade ratings;
- Including companies where less than 20% of the majority owner is publicly traded due to the control premium likely reflected in the valuation of its equity; and
- Including companies not rated by S&P or Moody's and thus lack an independent market participant assessment of its investment risk.

SCE clarified in its reply brief that its "model range recommendation does not rely on non-utility proxy groups."³³

EPUC/IS also take issue with SoCalGas including companies that are involved with a merger or acquisition and for including companies that do business in Canada. To account for these flaws, EPUC/IS proposed proxy groups for SCE, PG&E, and SoCalGas that adjust for the deficiencies that EPUC/IS asserts.

Del Monte asserts that it is inappropriate for PG&E to include non-energy utility firms in its sample. Del Monte asserts that the nature of a cost of service

³² EPUC/IS Opening Brief at 13.

³³ SCE Reply Brief at 7.

rate regulated firm is substantially different than other firms without this characteristic.

TURN notes that PG&E's witness "used several different proxy groups, including a "non-regulated" industry group and a regulated utility group that included utilities which violate the merger screen"³⁴ and recommends the Commission place very little weight on this comparison.

EDF indicates it is concerned with the cherry picking it perceives the applicants conducted when proposing proxy groups. EDF indicates SDG&E's witness eliminated 40% of the Value Line Sample, included Sempra as a peer, and eliminated the lowest proxy utility without justification other than it being an outlier.

We agree that PG&E's inclusion of CINI companies was inappropriate and counter to established policy for developing a proxy group of comparison companies. Further, we agree that the applicants selectively established a proxy group of companies and will review the model results with this in mind.

5.2. Financial Models

The financial models commonly used in ROE proceedings are the Capital Asset Pricing Model (CAPM), Risk Premium Model (RPM), and Discounted Cash Flow (DCF) Model. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the method and on the reasonableness of the proxies used to validate the results. Detailed descriptions of these financial models are contained in the record and are not repeated here.

³⁴ TURN Reply Brief at 18.

The Commission has historically indicated that we will not litigate the specific mechanics of each proposed model, inputs, and assumptions, and this decision continues to take this stance. The financial models are applied to a proxy group of companies comparable to the respective utility. A contributing factor resulting in a wide range of financial modeling results is the parties' difference in the time period and the availability of subjective inputs.

5.2.1. Flotation Costs

SDG&E and SoCalGas were the only parties that included flotation costs³⁵ as a subjective input into their respective financial models, resulting in an upward adjustment in its financial models of approximately 20 basis points.³⁶ While PG&E did not make an explicit flotation cost adjustment in its financial models, it recommended that such an adjustment be considered in evaluating a ROE for PG&E from within the results of its financial models.³⁷ The inclusion of flotation costs in the various financial models is not a new issue.

We concluded in D.92-11-047 that any merit to a flotation adjustment would apply only to existing common equity at the time of actual new issuances. We also concluded in that decision that a flotation adjustment is not applicable to sales in the secondary market, and that such an adjustment is inappropriate as long as utility stocks are trading significantly above their book value. We further concluded in that decision that any reconsideration of a flotation adjustment in a future proceeding would require a showing of theoretical, practical, utility and

³⁵ Flotation costs commonly include underwriter costs for marketing, consulting, printing and distribution, legal costs and discounts that must be provided to place a new common equity in the open market.

³⁶ Exhibits SDG&E-04 at 50 and SCG-04 at 55.

³⁷ Exhibit PGE-01 at 2-15.

market specific data, and a showing that a flotation cost adjustment does not shift the burden of the transaction costs from investors to ratepayers.³⁸

The utilities proposing a flotation adjustment have: (1) not identified any of their actual flotation costs; (2) not identified any new common equity issuances in the test year; and (3) not demonstrated that their utility stocks are trading at, or below, their book value. Consistent with the reasons set forth in D.92-11-047, we reject consideration of a flotation adjustment in this proceeding.

Consistent with prior Commission policy, SDG&E and SoCalGas's inclusion of flotation adjustments is inappropriate. The Commission will not grant the inclusion of flotation costs in setting the ROE for the applicants.

5.2.2. CAPM

The CAPM is a risk premium approach that gauges an entity's cost of equity based on the sum of an interest rate on a risk-free bond and a risk premium. Two primary variations to the CAPM were used by the parties, traditional and empirical CAPMs. The empirical CAPM (ECAPM) is designed to correct for the empirical observation that traditional CAPM does not properly estimate the cost of capital relative to the beta for stocks. However, the ECAPM tends to produce higher overall cost of capital estimates because adjusting betas for electric utilities, which tend to have low *betas*, upward guarantees a higher ROE.³⁹

Each party utilized different subjective inputs into their CAPM and ECAPM. For example, the average risk free rate utilized by parties ranged from

³⁸ 46 CPUC2d (1992) 319 at 362 and 406.

³⁹ 1 CPUC3d (1999) 146 at 168-169.

2.12% to 4.40%.⁴⁰ The following tabulation summarizes the simple average result of the CAPM variations calculated by the individual parties using subjective inputs.

	SCE	SDG&E	SoCalGas	PG&E
Utility	9.40% ⁴¹	8.75% ⁴²	9.10% ⁴³	9.40% ⁴⁴
FEA	6.00%	6.50%	N/A	6.00%
Cal Advocates	8.05%	8.05%	8.05%	8.05%
Del Monte	N/A	N/A	N/A	6.64%
EPUC/IS/TURN⁴⁵	8.50%	8.50%	8.50%	8.50%
UCAN/POC	N/A	7.71%	N/A	N/A

5.2.3. RPM

Similar to the CAPM, the RPM measures a company's cost of equity capital by adding a risk premium to a risk-free long-term treasury or utility bond yield. A risk premium is derived by an assessment of historic utility equity and bond returns, a historical RPM. A variation to the historical RPM is an allowed RPM which estimates the common equity allowed by regulatory commissions over a period of time in relationship to the level of long-term Treasury bond yield.

Each party utilized different subjective inputs into their RPMs. The following tabulation summarizes the simple average result of the RPM variations calculated by the individual parties using subjective inputs.

⁴⁰ TURN Opening Brief at 16.

⁴¹ Exhibit SCE-02 at 47 (result is for electric utility sample).

⁴² Exhibit SDG&E-04 at 43.

⁴³ Exhibit SCG-04 at 44 and 47.

⁴⁴ Exhibit PGE-01 at 2-13 (result is for electric utility sample).

⁴⁵ For SDG&E, TURN is the only party sponsoring the CAPM result.

	SCE	SDG&E	SoCalGas	PG&E
Utility	10.50% ⁴⁶	10.35% ⁴⁷	10.30% ⁴⁸	10.50% ⁴⁹
EPUC/IS/TURN ⁵⁰	9.00%	9.00%	9.00%	9.00%
UCAN/POC	N/A	9.71%	N/A	N/A

5.2.4. DCF

The DCF model is used to estimate an equity return from a proxy group by adding estimated dividend yields to investors' expected long-term dividend growth rate. Variations used by the parties include constant growth⁵¹ and multi-stage growth.⁵²

Each party utilized different subjective inputs into their various DCF models. The following tabulation summarizes the simple average result of different versions of the DCF model calculated by the individual parties using subjective inputs.

	SCE	SDG&E	SoCalGas	PG&E
Utility	9.10% ⁵³	9.62% ⁵⁴	10.02% ⁵⁵	9.05% ⁵⁶
FEA	8.75%	9.00%	N/A	8.50%
Cal Advocates	8.52%	8.52%	8.05%	8.52%
Del Monte	N/A	N/A	N/A	7.37%

⁴⁶ Exhibit SCE-02 at 55.

⁴⁷ Exhibit SDG&E-04 at 48.

⁴⁸ Exhibit SCG-04 at 49 and 52.

⁴⁹ Exhibit PGE-01 at 2-67.

⁵⁰ For SDG&E, TURN is the only party sponsoring the RPM result.

⁵¹ The growth rate investors expect over the long term.

⁵² Multi-stage growth reflects the possibility of non-constant growth for a company over time.

⁵³ Exhibit SCE-02 at 52 (result is for electric utility sample).

⁵⁴ Exhibit SDG&E-04 at 26-28 (does not include flotation costs).

⁵⁵ Exhibit SCG-04 at 26-27 (result is for natural gas utility sample).

⁵⁶ Exhibit PGE-01 at 2-13.

EPUC/IS/TURN ⁵⁷	8.70%	8.60%	8.60%	8.70%
UCAN/POC	N/A	8.62%	N/A	N/A

5.2.5. Summary

From the results of these broad financial models which are dependent on subjective inputs, the parties advance arguments in support of their respective analyses and in criticism of the input assumptions used by other parties. These arguments will not be addressed extensively in this decision. It should be noted that none of the parties agreed with the financial modeling results of the others.

In the final analysis, it is the application of informed judgment, not the precision of financial models, which is the key to selecting a specific ROE estimate. We affirmed this view in D.89-10-031, noting that it is apparent that all these models have flaws and, as we have routinely stated in past decisions, the models should not be used rigidly or as definitive proxies for the determination of the investor-required ROE. Consistent with that skepticism, we found no reason to adopt the financial modeling of any one party. The models are helpful as rough gauges of the realm of reasonableness.

5.3. Additional Risk Factors

We also consider additional risk factors not specifically included in the financial models. Those additional risk factors fall into three categories: financial, business and regulatory.

5.3.1. Financial Risk

Financial risk is tied to the utility's capital structure. The proportion of its debt to permanent capital determines the level of financial risk that a utility faces. As a utility's debt ratio increases, a higher ROE may be needed to

⁵⁷ For SDG&E, TURN is the only party sponsoring the DCF result.

compensate for that increased risk. However, in this proceeding, there is minimal change in financial risk because the debt ratios being adopted in this proceeding are not materially changed from the utilities' last authorized debt ratios.

Debt equivalence, raised as a financial risk by the applicants, does have an impact on the financial risk of SCE, PG&E, SDG&E, and SoCalGas. As recognized in D.04-12-047, debt equivalence has been reflected in the utilities' credit ratings since at least 1990. In D.05-12-043, we affirmed that debt equivalence would 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. Our goal in so doing was, and continues to be, to provide reasonable confidence in the utilities' financial soundness, to maintain and support investment-grade credit ratings, and provide utilities the ability to raise money necessary for the proper discharge of their public duty. We have no reason to change that goal. Debt equivalence is considered in arriving at an overall ROE.

5.3.2. Business Risk

Business risk pertains to *new* uncertainties resulting from competition and the economy. An increase in business risk can be caused by a variety of events that include capital investments, electric procurement, and catastrophic events. Each of these business risks overlap into financial and regulatory risk.

5.3.2.1. Transformation of the Electric Grid

SCE discusses at length many of the risks it perceives as it executes the goals of California in terms of grid modernization. These risks SCE identifies include increased renewables portfolio standard requirements, transportation electrification, updating aging infrastructure, and increased commodity competition.

EDF notes that California has long been supportive of the utilities that undergo the work necessary to advance the clean energy and modernization goals of California. EDF also points to a Form 10-K filing from SCE that notes that there is shareholder value that can be derived from these activities.

Long-term we remain firmly committed to our corporate strategy of leading the transformative change under way in the electric power industry by pursuing opportunities in clean energy, efficient electrification, grid modernization, and customer choice thereby delivering value to shareholders.⁵⁸

While these activities are highly complex and require significant technical and project management expertise, California has established an extensive and supportive framework for the IOUs that undertake these activities. This risk is already priced into the models.

5.3.2.2. Wildfire Risk

The three applicants with electric operations (SCE, SDG&E, and PG&E) assert that they face greater risks than peer utilities due to wildfires and resulting utility liability under inverse condemnation that is unique to California.⁵⁹ SCE, SDG&E, and PG&E are requesting an increase to the authorized ROE over the financial model results to compensate investors for these perceived wildfire risks.

The Scoping Ruling issued on July 2, 2019 indicated that

The Commission will not consider a separate wildfire adder in the scope of this proceeding. Risk[s] of all kind are addressed

⁵⁸ Exhibit EDF-06, SCE 10-K Letter to Shareholders at 2.

⁵⁹ PG&E Opening Brief at 10. While SoCalGas asserts that the inverse condemnation policy in California would apply to its assets, it admits that the risks of wildfires are most significant for overhead electric conductors, which it does not employ in the provision of gas service to customers, and it has not requested a wildfire risk adder.

in this proceeding; thus a separate adder is not appropriate for one risk.

Additionally, the assigned Administrative Law Judge issued a ruling on July 15, 2019 directing the applicants to serve supplemental testimony on how AB 1054 affects the financial risks described in the applicants’ opening testimony. All four applicants complied with this ruling and provided supplemental testimony. SCE, SDG&E, and PG&E all significantly lowered their requested total ROE and removed requests for a specific wildfire adder, although the revised requested ROE for each remained above their initial base ROE requests, as shown below:

IOU	Current ROE	Base ROE Requested pre-AB 1054	Wildfire Adder Requested pre-AB 1054	Total ROE Requested pre-AB 1054	Wildfire Adjustment Requested post-AB 1054 to base ROE	Total ROE Requested post-AB 1054
SCE	10.30%	10.60%	6.00%	16.60%	0.85%	11.45%
PG&E	10.25%	11.00%	5.00%	16.00%	1.00%	12.00%
SDG&E	10.20%	10.90%	3.40%	14.30%	1.48%	12.38%
SoCalGas	10.05%	10.70%	0.00%	10.70%	n/a	10.7%

SCE, SDG&E, and PG&E assert that AB 1054 mitigates wildfire risk but argue that it does not eliminate it, and thus a higher ROE is necessary. These arguments center around several premises.

- California has a higher propensity for fires in highly populated and property dense areas.
- AB 1054 did not address inverse condemnation, and California’s application of inverse condemnation with strict liability to utilities is unique to California.
- Credit rating agencies, which investors use to assess risk, still perceive risk from wildfires in California.

- Implementation risk associated with AB 1054 based on uncertainty towards the Commission's application of the new reasonableness standard for cost recovery.
- Concerns that the wildfire fund may be exhausted earlier than 2035.
- Wildfire risk is not captured in the standard cost of capital models and should be modeled separately.

IEI echoes these remarks regarding its position on the appropriate ROE for PG&E. IEI puts forth the notion that the SDG&E Wildfire Expense Memorandum Account Decision⁶⁰ by the Commission modified the understanding of the investment community of the financial risk of California. IEI indicated that "investors realized that the extraordinary liabilities caused by these wildfires could be imposed on California IOUs through inverse condemnation and shifted from ratepayers to shareholders by application of the prudent manager standard."⁶¹

TURN argues that these assertions ignore the fundamental impact of AB 1054 in ameliorating the actual risk faced by utility investors and ignores the positive market response to AB 1054.⁶² TURN points out that even if there is some market uncertainty regarding implementation of AB 1054, this at most justifies adopting an ROE at the high end of valid ROE modeling outcomes but does not justify adding premiums on top of the modeling results.⁶³

⁶⁰ D.17-11-033.

⁶¹ IEI Opening Brief at 28-29.

⁶² TURN Opening Brief at 38.

⁶³ TURN Reply Brief at 7.

EPUC/IS argues that the risk premium requested by the applicants is unjust and not supported by the law and policy in California. EPUC/IS notes that AB 1054 benefits utility shareholders in a multitude of ways:⁶⁴

- Creates a Wildfire Fund funded jointly by ratepayer and shareholder contributions that will provide liquidity and a source of funding from which to pay wildfire claims;
- Caps shareholder responsibility for cost disallowance at 20% of an IOU's transmission and distribution rate base;
- Creates a presumption of reasonableness for a utility with a valid wildfire safety certification from the Commission's executive director;
- Shifts the burden of proof to ratepayers to demonstrate under the new "serious doubt" standard that wildfire costs were imprudently incurred; and
- Provides clarity and certainty in the prudent manager standard, negating the standards applied in addressing wildfire costs arising from SDG&E's 2007 wildfire claims.

FEA contends that two critical aspects of AB 1054 reduce risk to utilities: the creation of a new prudence standard for determining if a utility's covered wildfire costs are just and reasonable, and the development of a cap on wildfire-related expenses found to be imprudent.⁶⁵ FEA observes that the utilities (specifically SDG&E) "seemingly wants to shift all the risk, even if a wildfire was the result of an IOU's action, to consumers."⁶⁶

Thomas Del Monte concludes that, regarding residual risk to shareholders that remains from catastrophic wildfires, this is a risk "that is the fault of

⁶⁴ EPUC/IS Opening Brief at 101.

⁶⁵ FEA Opening Brief at 11.

⁶⁶ FEA Reply Brief at 3.

management controlled by the stockholders, it should not be compensated via ROE adders...”⁶⁷

Given that parties have made various assertions regarding the impact on wildfire risk faced by electric utilities, we review relevant provisions of AB 1054 to provide the context for the determinations made in this decision on the Test Year 2020 Cost of Capital.

AB 1054 was enacted, in part, because, the financial effects of catastrophic wildfires had placed the state’s electric industry in an “unprecedented state of instability.”⁶⁸ Among other things, in enacting AB 1054 the Legislature found that “creation of a wildfire insurance fund will reduce the costs to ratepayers in addressing utility-caused catastrophic wildfires” and further that the “establishment of a wildfire fund supports the credit worthiness of the electrical corporations and provides a mechanism to attract capital for investment in safe, clean, and reliable power for California at a reasonable cost to ratepayers.”⁶⁹ The Legislature also noted its intent “to provide a mechanism that allows electrical corporations that are safe actors to guard against impairment of their ability to provide safe and reliable service because of the financial effects of wildfires in their service territories using mechanisms that are more cost effective than traditional insurance, to the direct benefit of ratepayers and prudent electrical corporations.”⁷⁰

As the Commission recently explained, AB 1054 set forth two alternative potential constructs for the wildfire fund, either through operation of a Wildfire

⁶⁷ Del Monte Opening Brief at 41.

⁶⁸ Pub. Util. Code § 854.2(a)(6).

⁶⁹ AB 1054, 2019-2020 Reg. Sess. (Stats. 2019, ch. 81), § 1(a)(3), (4).

⁷⁰ AB 1054, 2019-2020 Reg. Sess. (Stats. 2019, ch. 81), § 1(b).

Liquidity Fund or a Wildfire Insurance Fund.⁷¹ At this time, the Wildfire Insurance Fund is operative as all three of the large electrical corporations have taken the required steps to participate or become eligible to participate.⁷²

Capitalization of the Wildfire Fund. Shareholders of participating large electrical corporations must make a one-time initial contribution and ongoing annual contributions toward the capitalization of the Wildfire Fund, which will total approximately \$10.5 billion (assuming PG&E participates). SCE and SDG&E have made their initial contributions.⁷³ Once a participating electrical corporation has made its commitment to participate in the fund, it must continue participating and fully satisfy the required annual shareholder contributions.⁷⁴ AB 1054 prohibits the initial and annual shareholder contributions from being recovered from ratepayers,⁷⁵ but also allows for ratepayers to make an approximately equal contribution towards capitalization of the Wildfire Fund subject to Commission approval.⁷⁶ In D.19-10-056 the Commission approved the imposition of a nonbypassable charge on ratepayers of participating electrical corporations and established a revenue requirement of \$902.4 million annually

⁷¹ D.19-10-056 at 46, *see also* Pub. Util. Code §§ 3291, 3292.

⁷² D.19-10-056 at 96, PG&E can participate in the fund by exiting bankruptcy and satisfying other statutory criteria before June 30, 2020. For purposes of this proceeding we assume that PG&E will participate in the Wildfire Insurance Fund (PG&E Opening Brief at 6, 42).

⁷³ PG&E will not make initial or annual shareholder contributions until after it has met the requirements for participation and has exited its insolvency proceeding. Pub. Util. Code §§ 3292(e).

⁷⁴ D.19-10-056 at Ordering Paragraph 1.

⁷⁵ Pub. Util. Code §§ 33929(b)(3), (c).

⁷⁶ Pub. Util. Code § 3289(a)(1).

(assuming PG&E participates) to support the Wildfire Fund.⁷⁷ These nonbypassable charges will begin in the month after an existing charge, the California Department of Water Resources (DWR) Bond Charge, stops being collected, at a specific date to be determined following further proceedings in R.19-07-017.⁷⁸

Many features of the Wildfire Fund nonbypassable charge mirror the historic DWR Bond Charge. The annual revenue requirement approved by the Commission is a fixed amount based on the past collections under the DWR Bond Charge.⁷⁹ The charge is to be collected “in the same manner as” the DWR Bond Charge,⁸⁰ and D.19-10-056 specifies certain implementation details regarding this statutory requirement.⁸¹

Decision 19-10-056 also approved a rate agreement between the CPUC and DWR that provides for the administration of the revenue requirement and additional provisions, some of which are designed to facilitate the issuance of a tax-free bond by DWR to capitalize the Wildfire Fund or repay its loans.⁸²

Uses of Funds. Shareholder contributions are paid to the fund directly, and ratepayer contributions paid via the nonbypassable charge are remitted to DWR (to the DWR Charge Fund).⁸³ Funds held by DWR and the Wildfire Fund are to

⁷⁷ D.19-10-056 at 1, 12. The revenue requirement will be determined after June 30, 2020 in Rulemaking 19-07-017 and depends upon whether PG&E participates.

⁷⁸ D.19-10-056 at 32, Pub. Util. Code § 3289(a)(2).

⁷⁹ D.19-10-056 at 10-12, 20, Water Code § 80524(a).

⁸⁰ Pub. Util. Code § 3292(a)(2).

⁸¹ D.19-10-056 at 25-30.

⁸² See also Water Code, §§ 80540, 80542(a), (b), (d).

⁸³ Compare Pub. Util. Code § 3289(a)(2) with Pub. Util. Code § 3292(b)(3).

be used for the purposes specified in the controlling statutes. DWR is authorized to support a bond issuance, the proceeds of which will be deposited in the Wildfire Fund,⁸⁴ and to use moneys collected via the nonbypassable charge to service the bond debt and other costs; it may then transfer any remaining revenue requirement directly to the Wildfire Fund.⁸⁵

Funds held by the Wildfire Fund may be invested for growth and may be used to buy insurance, pay eligible claims under the mechanism described in Sections 1701.8 and 3292(f) of the Public Utilities Code, or may be utilized by the Wildfire Fund Administrator to undertake other activities described in Sections 3281 and 3285 of the Public Utilities Code. The Wildfire Fund must report annually to the Legislature on its administration of the fund⁸⁶ and will continue in existence, with all monies remaining in the fund remaining available to pay claims, until its resources are exhausted.⁸⁷

The Wildfire Insurance Fund provides a financial backstop for eligible claims exceeding \$1 billion per utility, or the amount of insurance coverage required, per calendar year.⁸⁸ A utility may seek payment from the Wildfire Fund for eligible third-party liability claims that are settled or finally adjudicated. Once reviewed, and if they are approved by the fund administrator as being in the reasonable business judgment of the electrical corporation, funds will be released to the electrical corporation for payment of claims.⁸⁹

⁸⁴ Water Code § 80540.

⁸⁵ Water Code §§ 80544(a).

⁸⁶ Pub. Util. Code § 3287(b).

⁸⁷ Pub. Util. Code § 3292(i).

⁸⁸ Pub. Util. Code § 3280(f).

⁸⁹ Pub. Util. Code § 3292(f).

Subrogation claims are authorized for settlement at 40% of total asserted claim value unless the Fund Administrator finds sufficient reason to increase the payment rate.⁹⁰ If a utility has received payments from the Wildfire Fund for third party claims it shall file an application for cost recovery with the Commission to determine whether the costs are just and reasonable.⁹¹ This construct allows the electrical utilities to access the fund to pay claims to wildfire victims quickly, addressing concerns over liquidity and need to access funding between the time of payment to wildfire victims and when regulatory determinations of rate recovery are made.

Fund Replenishment. In regards to cost recovery, AB 1054 also altered the Commission's standard of review when making a determination of the reasonableness of wildfire costs for a utility with a valid safety certification, by creating a presumption that a utility's conduct was reasonable "unless a party to the proceeding creates a serious doubt as to the reasonableness of the electrical corporation's conduct."⁹² Wildfire costs and expenses may also be allocated for cost recovery (i.e. allowance or disallowance) taking into account factors that may have exacerbated them.⁹³ In D.19-10-056, the Commission clarified that a utility has already recovered costs paid by the Wildfire Fund that the Commission determines were prudently incurred.⁹⁴ The Commission further found that ratepayers will not reimburse the Wildfire Fund for withdrawals used

⁹⁰ Pub. Util. Code § 3292(f).

⁹¹ Pub. Util. Code § 1701.8.

⁹² Pub. Util. Code § 451.1(c).

⁹³ Pub. Util. Code § 451.1(b).

⁹⁴ D.19-10-056 at 36.

to pay prudently incurred eligible wildfire claims.⁹⁵ Utility shareholders, by contrast, must reimburse the Wildfire Fund for any costs that the Commission disallows, up to a cap set at 20% of the utility's transmission and distribution equity rate base (calculated on a 3-year rolling basis).⁹⁶ Thus, AB 1054 caps the total unrecoverable liability utility shareholders face for wildfire costs even where the utility is found to have acted imprudently – unless the utility failed to maintain a valid safety certification or the fund administrator determines that the utility actions constituted “conscious or willful disregard of the rights and safety of others.”⁹⁷

Regarding implementation risk relating to the application of a new prudence standard, this does not introduce a new risk but rather a solution that is expected to limit utilities' financial exposure to wildfire liabilities in the future. Shareholders are only required to repay the fund for imprudent wildfire costs, and only up to a cap. Undisputed in this proceeding is the notion that the investor owned utilities should not be awarded with an increased ROE based on risk that is associated with imprudent management. The residual risk for shareholders of financial losses due to catastrophic wildfires after the signing of AB 1054 is for imprudent actions taken by the IOUs that resulted in a catastrophic wildfire. The standard set in Bluefield and Hope is that investor owned utilities should not be rewarded with an ROE that is inflated due to imprudent actions. Further, while AB 1054 did not modify the common law of inverse condemnation, the Commission may now allocate a utility's allowed and

⁹⁵ D.19-10-056 at 36.

⁹⁶ Pub. Util. Code § 3292(h)(2)(C).

⁹⁷ Pub. Util. Code §§ 3292(h)(2)(A), 3292(h)(2)(B).

disallowed wildfire costs and expenses from wildfires in full or in part taking into account exacerbating factors. Finally, arguments positing that the fund may be exhausted before 2035 are premature; there is no evidence that the long-term durability of the fund poses residual risks today that the Commission need address in determining ROE for the 2020 test year cost of capital.

We find that the passage of AB 1054 and other investor supportive policies in California have mitigated wildfire exposure faced by California's utilities. Accordingly, the Commission will not authorize a specific wildfire risk premium in the adopted ROE. In addition to the reasons summarized above, this is further supported by the August 15, 2019 S&P Global RRA Regulatory Focus that acknowledges that any residual factors of risk that may exist for investor owned utilities in California post the adoption of AB 1054 are more or less offset by the more constructive aspects of the California regulatory framework, which accounts for California's placement within a balanced category.⁹⁸

5.3.3. Regulatory Risk

Regulatory risk pertains to *new* risks that investors may face from future regulatory actions that we, and other regulatory agencies, might take. Regulatory risk assessment is also used by rating agencies to set utility bond ratings. SCE, SDG&E, and SoCalGas have investment grade bond ratings. For example, SCE has an S&P bond rating of BBB, SDG&E a BBB+ and SoCalGas an A. PG&E currently is in voluntary bankruptcy proceedings and has a D rating. The A ratings are considered by S&P to be upper medium investment grade level and

⁹⁸ Exhibit SDG&E-20C.

BBB+ and BBB to be medium investment grade level.⁹⁹ With the exception of PG&E's voluntary bankruptcy impacting its credit rating, these investment grade ratings are a good indication that California regulatory risks are low.

Nevertheless, we will address the parties' regulatory risk testimony, which fall into three categories: (1) authorized ROE; (2) cost recovery; and (3) regulatory lag.

5.3.3.1. Authorized ROE Risk

An authorized ROE has risk when it does not adequately compensate a utility for the risk that investors must assume. California is generally perceived as having a constructive regulatory environment. However, the utilities are concerned that a lower ROE could potentially harm their credit profile and increase their cost of capital during a time when they need to spend substantial amounts on capital investment projects, above their historic norm.

California utilities are not the only utilities experiencing an increase of capital investment projects. Therefore, the parties' financial modeling results derived from various proxy groups already include the impact of increasing capital investment by utilities outside of California. Further, the utilities authorized ROE risk concern is without merit because we consistently set the rate of return at a level that meets the test of reasonableness as set forth in the Bluefield and Hope cases and we will continue to do so.

5.3.3.2. Cost Recovery Risk

Cost recovery risk occurs when a utility is precluded from having the ability to fairly and consistently recover its cost in a timely manner. Identified

⁹⁹ S&P has four investment grade levels, the lowest level is medium grade (BBB-, BBB, and BBB+ ratings), upper grade (A-, A, and A+), high grade (AA-, AA, and AA+), and highest grade of AAA.

cost recovery issues included: (1) power procurement commitments; (2) balancing and memorandum accounts; and, (3) revenue decoupling. There are opposing sides to this risk argument. However, a review of California regulatory commissions compared to others around the country have rated California regulatory commissions as “highly supportive of cost recovery.”¹⁰⁰

5.3.3.3. Regulatory Lag Risk

Regulatory Lag is commonly defined to be a delay in a utility’s ability to recover costs in a timely manner. The utilities contend that they need to be compensated for increased regulatory lag because of extended periods of uncertain outcomes from Commission proceedings which extend beyond the statutory 18-month period. EPUC/IS responds by stating that this risk has already been solved by the long-standing and active use of balancing accounts. Balancing accounts “significantly mitigate the cost recovery risk due to forecast uncertainty when rates are in effect.”¹⁰¹

5.3.3.4. Other Regulatory Risks

Other regulatory risks identified by the parties include changes in government laws and regulations and municipalization of regulated utilities. These changes have occurred and are expected to continue. To the extent that investors expect government laws and regulations to change and municipalization of regulated utilities to occur, such expectations should already be captured in the financial modeling results.

¹⁰⁰ Exhibit EPUC/IS/TURN-01 at IV-5:13-14.

¹⁰¹ Exhibit EPUC/IS/TURN-01 at IV-2:18.

5.4. Summary

The utilities are being increasingly driven by financial, business and regulatory factors that include energy availability, ability to attract capital to raise money for the proper discharge of their public utility duties and to maintain investment-grade creditworthiness, all of which are important components of the Hope and Bluefield decisions. Based on the above financial, business and regulatory risks discussion, we conclude that the ROE ranges adopted in this proceeding from the various financial models adequately compensate the utilities for these risks.

Having addressed the generic factors used in setting an ROE we now address a fair and reasonable return for the individual utilities. We also consider the utilities credit ratios and how debt equivalency impacts those credit ratios.

5.5. SCE's Return on Equity

The following tabulation summarizes the final ROE proposals by SCE and the intervenors.

Party	Final Proposed ROE
SCE	11.45%
Cal Advocates	8.65%
FEA	9.75%
EPUC/IS/TURN	9.65%

SCE's requested 11.45% ROE is higher than the midpoints of its financial modeling results.

After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models, additional risk factors including business risk, and interest coverage presented by the parties and applying our informed judgment, we adopt a just and reasonable ROE range of 9.8% to 10.6%. We conclude that the adopted ROE should be set at

the upper end of the just and reasonable range. We find that SCE's authorized test year 2020 ROE should be 10.30%. This ROE is reasonably sufficient to assure confidence in the financial soundness of the utility and to maintain investment grade credit ratings while balancing the interests between shareholders and ratepayers. We further observe that the 10.30% authorized ROE is significantly higher than the 9.60%¹⁰² average ROEs granted to United States electric utilities during 2018.

5.6. PG&E's Return on Equity

The following tabulation summarizes the final ROE proposals by PG&E and the intervenors.

Party	Final Proposed ROE
PG&E	12.00%
Cal Advocates	8.49%
FEA	9.75%
EPUC/IS/TURN	9.00% gas, 9.65% electric
Del Monte	8.58%
IEI	15.25%

PG&E's requested 12.00% ROE is higher than the midpoint of its financial modeling results.

After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models, additional risk factors including business risk, and interest coverage presented by the parties and applying our informed judgment, we adopt a just and reasonable ROE range of 9.65% to 10.45%. We conclude that the adopted ROE should be set at the upper end of the just and reasonable range. We find that PG&E's authorized test year 2020 ROE should be 10.25%. This ROE is reasonably sufficient to assure

¹⁰² Exhibit EPUC/IS-3-C S&P Global Market Intelligence, July 22, 2019 at Table 1.

confidence in the financial soundness of the utility while balancing the interests between shareholders and ratepayers. We further observe that the 10.25% authorized ROE is significantly higher than the 9.60%¹⁰³ average ROEs granted to United States electric utilities during 2018.

5.7. SDG&E's Return on Equity

The following tabulation summarizes the final ROE proposals by SDG&E and the intervenors.

Party	Final Proposed ROE
SDG&E	12.38%
Cal Advocates	8.49%
FEA	9.50%
UCAN/POC	9.15%
TURN	9.65%

SDG&E's requested 12.38% ROE is higher than the midpoint of its financial modeling results. Further, as noted, SDG&E included flotation costs, and consistent with previous Commission policy, SDG&E has not met the standards necessary for the Commission to consider these flotation costs in the adopted ROE figure.

After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models, additional risk factors including business risk, and interest coverage presented by the parties and applying our informed judgment, we adopt a just and reasonable ROE range of 9.60% to 10.40%. We conclude that the adopted ROE should be set at the upper end of the just and reasonable range. We find that SDG&E's authorized test year 2020 ROE should be 10.20%. This ROE is reasonably sufficient to assure confidence in the financial soundness of the utility and to

¹⁰³ Exhibit EPUC/IS-3-C S&P Global Market Intelligence, July 22, 2019 at Table 1.

maintain investment grade credit ratings while balancing the interests between shareholders and ratepayers. We further observe that the 10.20% authorized ROE is significantly higher than the 9.60%¹⁰⁴ average ROEs granted to United States electric utilities during 2018.

5.8. SoCalGas’s Return on Equity

The following tabulation summarizes the final ROE proposals by SoCalGas and the intervenors.

Party	Final Proposed ROE
SoCalGas	10.70%
Cal Advocates	8.49%
EPUC/IS/TURN	9.00%

SoCalGas’s requested 10.70% ROE is higher than the midpoint of its financial modeling results.

After considering the evidence on market conditions, trends, creditworthiness, interest rate forecasts, quantitative financial models, additional risk factors including business risk, and interest coverage presented by the parties and applying our informed judgment, we adopt a just and reasonable ROE range of 9.40% to 10.30%. We conclude that the adopted ROE should be set at the upper end of the just and reasonable range. We find that SoCalGas’s authorized test year 2020 ROE should be 10.05%. This ROE is reasonably sufficient to assure confidence in the financial soundness of the utility while balancing the interests between shareholders and ratepayers. We further observe that the 10.05% authorized ROE is significantly higher than the 9.59%¹⁰⁵ average ROEs granted to United States gas utilities during 2018.

¹⁰⁴ Exhibit EPUC/IS-3-C S&P Global Market Intelligence, July 22, 2019 at Table 1.

¹⁰⁵ Exhibit EPUC/IS-3-C S&P Global Market Intelligence, July 22, 2019 at Table 1.

6. Implementation

SCE, PG&E, SDG&E, and SoCalGas shall implement the revenue requirement changes authorized by this decision in their respective end-of-the-year consolidated revenue requirement Tier 1 advice letter filings, also referred to as Annual Electric True-Ups or Annual Gas True-Ups, for effective dates no earlier than January 1, 2020.

7. Cost of Capital Mechanism

Developed in D.08-03-035 and continued in D.13-03-015, the Commission created a cost of capital mechanism (CCM) that applied to SCE, PG&E, and SDG&E. SoCalGas had a similar mechanism, the Market Indexed Capital Adjustment Mechanism (MICAM) since 1996.

The CCM determined that a full cost of capital application is due April 20 of every third year following the test year. In the interim years, however, cost of capital for the IOUs is determined by the CCM based on set factors.

Both SCE and PG&E propose to keep the existing CCM structure in place without modifications. Cal Advocates and EPUC also support the retention of the existing CCM.¹⁰⁶

SDG&E and SoCalGas also support keeping the CCM, however these two applicants recommend slight modifications to the structure of the mechanism. The modifications these applicants suggest include narrowing the 100 basis points dead band to 50 basis points and adding a few clarifications to address the recent instability of utility credit ratings.

PG&E responded to the suggested modifications by SDG&E and SoCalGas.

¹⁰⁶ Exhibit Cal Advocates-09 at 2.

The SoCalGas and SDG&E proposal to reduce the dead band would make the mechanism more likely to trigger, and PG&E does not believe that this is a necessary change. PG&E appreciates SoCalGas and SDG&E's sensitivity to situations where utilities have split ratings and their request for guidance for utilities with non-investment grade ratings. However, PG&E does not support those requests at this time.¹⁰⁷

The only opposition to continuing the cost of capital mechanism came in Witness Knecht's testimony for Del Monte.¹⁰⁸ Knecht notes that "[i]t has kept allowed ROEs and rates unduly high for nearly a decade. It shifts to customers risks that should be carried by stockholders." However, the record does not strongly support this statement.

The record strongly supports continuing the existing structure of the CCM. There may be some merit to the modifications suggested by SDG&E and SoCalGas, however the Commission will not adopt these modifications at this time. The existing CCM shall remain in place for the four applicants in this proceeding.

There may be some merit to the proposal of SDG&E and SoCalGas to narrow the dead band from the current 100 basis points in the existing and approved CCM. The applicants shall coordinate with the Commission's Energy Division, to the extent the Commission's Energy Division deems necessary, to assist with analysis that will determine the impact of modifying the dead band in the CCM.

¹⁰⁷ PG&E Opening Brief at 38.

¹⁰⁸ Exhibit Del Monte-01 at 59.

8. Should PG&E be required to file a new Cost of Capital Application once it emerges from Chapter 11 bankruptcy proceedings?

PG&E notes that there is significant uncertainty about its emergence from Chapter 11 bankruptcy.

PG&E notes that if it satisfies the requirements of AB 1054 and participates in the Wildfire Fund, a new Application would not be necessary for the purposes of evaluating that scenario, as this consideration is already taking place in this proceeding.¹⁰⁹ However, PG&E notes that if it is not able to or elects to not participate in the Wildfire Fund, a new application would be necessary. PG&E also notes that the cost of debt authorized in this decision will likely be different after its emergence from Chapter 11 bankruptcy.

TURN supports a requirement being established in this decision for PG&E to file a new Application after its emergence from bankruptcy.

PG&E's forecast of the cost of debt in this case is higher primarily due to the higher cost of debt from PG&E's \$5.5 billion, court-approved Debtor-In-Possession facilities.¹¹⁰ While the market experiences declining interest rates, PG&E is locked out of issuing new bonds for debt equity. PG&E's debt financing should stabilize after exiting bankruptcy. It should be required to file an application within three months of exiting bankruptcy to update its debt cost forecast. PG&E should not be allowed to collect higher than necessary returns for debt costs if its actual costs of debt decline after bankruptcy.¹¹¹

Del Monte does not support the Commission directing a re-litigation of PG&E's 2020 Test Year Cost of Capital once the utility emerges from bankruptcy.

¹⁰⁹ PG&E Opening Brief at 42.

¹¹⁰ Exhibit PG&E-01 at 5-1.

¹¹¹ TURN Opening Brief at 90.

The Commission has an active docket to evaluate issues specifically pertaining to PG&E and its current bankruptcy proceeding,¹¹² and that is the more appropriate proceeding within which to consider this issue. This decision does not take a position or establish any orders pertaining to whether PG&E should be required to submit a new cost of capital Application following its emergence from Chapter 11 bankruptcy.

9. PG&E Customer Deposits

In addressing PG&E's 2014 general rate case (GRC), the Commission directed "that a comprehensive review of the treatment of customer deposits should be made in the next cost of capital proceeding."¹¹³

PG&E presented a complete evaluation of ratemaking for customer deposits in its testimony. That testimony explained that if a utility holds customer deposits as cash (normally in money market funds), then there is no ratemaking treatment for customer deposits, because the cash is not being used for utility operations. PG&E also explained that customer deposits are like debt,¹¹⁴ and when the cash is used for utility operations, the appropriate assumption is that the customer deposits replace an equal amount of conventional debt that otherwise would be financing rate base.¹¹⁵ PG&E notes that this is the ratemaking method adopted in PG&E's 2014 GRC (D.14-08-032).

TURN's opening brief states "[t]he Commission Should Not Change the Ratemaking Treatment of Customer Deposits Adopted in D.14-08-032."¹¹⁶

¹¹² Investigation 19-09-016.

¹¹³ D.14-08-032 at 629.

¹¹⁴ Exhibit PGE-01 at 7-1.

¹¹⁵ Exhibit PGE-01 at 7-3.

¹¹⁶ TURN Opening Brief at 87.

Del Monte also supported the existing treatment of customer deposits.¹¹⁷

It appears these parties agree that the ratemaking treatment adopted in D.14-08-032 should be continued.¹¹⁸

PG&E has fulfilled its obligation to provide a comprehensive review of the ratemaking treatment for customer deposits, as directed in D.14-08-032. There is no compelling information in the record to suggest a modification from the direction provided for the ratemaking treatment of customer deposits in D.14-08-032.

10. Procedural Matters

The Commission affirms all rulings made by the assigned Commissioner and assigned ALJ. All motions not previously ruled on are denied as moot.

11. Reduction of Comment Period

Pursuant to Rule 14.6(b) of the Commission's Rules of Practice and Procedure, all parties stipulated to reduce the 30-day public review and comment period required by Section 311 of the Public Utilities Code to 15 days. Pursuant to the parties' stipulation, comments were filed on December 13, 2019 by the four applicants, Cal Advocates, Del Monte, the City and County of San Francisco, EDF, IEL, EPUC/IS, TURN, UCAN/POC, and the County of San Diego. Reply comments were filed on December 17, 2019 by the applicants, UCAN/POC, EDF, EPUC/IS, the Ad Hoc Committee of Senior Unsecured Noteholders of Pacific Gas & Electric Company, TURN, IEL, and Del Monte. Minor changes were made throughout the Proposed Decision to clarify its intent.

¹¹⁷ Exhibit Del Monte-1 at 60.

¹¹⁸ PG&E Reply Brief at 17 and TURN Opening Brief at 87.

12. Assignment of Proceeding

Marybel Batjer is the assigned Commissioner and Brian Stevens is the assigned ALJ in this proceeding.

Findings of Fact

1. Applicants are public utilities subject to the jurisdiction of this Commission.
2. SCE, PG&E, SDG&E, and SoCalGas's applications were consolidated.
3. All four applicants requested modifications to their authorized capital structure.
4. SDG&E sought to eliminate its capital structure authorization for preferred equity, and SoCalGas sought to substantially reduce its capital structure authorization for preferred equity.
5. Both SDG&E and SoCalGas sought capital structure authorizations for common equity of 56%.
6. PG&E and SCE sought capital structure authorizations for common equity of 52%.
7. Of 47 pending rate cases nationally, only four request a common-equity ratio of 56% or more.
8. SDG&E's current approved common-equity ratio of 52% is larger than 70.5% of all authorized common-equity ratios nationwide from the time period of 2017 through July 2019.
9. Parties stipulated approval in a joint filing on August 29, 2019 as to the proposed cost of long-term debt by SCE, SDG&E, and SoCalGas.
10. Parties stipulated approval in a joint filing on August 29, 2019 as to the proposed cost of preferred equity by SCE, PG&E, and SoCalGas.

11. SDG&E did not propose an updated cost of preferred equity; however, its current authorized cost of preferred equity is 6.22%.

12. No party opposed PG&E's proposed cost of long-term debt.

13. SCE seeks a test year 2020 ROE authorization of 11.45%.

14. PG&E seeks a test year 2020 ROE authorization of 12.00%.

15. SDG&E seeks a test year 2020 ROE authorization of 12.38%.

16. SoCalGas seeks a test year 2020 ROE authorization of 10.70%.

17. An ROE is set at a level of return commensurate with market returns on investments having corresponding risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility obligation.

18. SCE, PG&E, SDG&E, and SoCalGas used electric utility industry group lists from Value Line to establish proxy groups to be used in their financial models.

19. SCE proposed a proxy group that includes electric and water and natural gas utilities.

20. PG&E proposes several different proxy groups, including a "non-regulated" industry group and a regulated utility group that included some utilities that are undergoing a restructure or merger.

21. The other intervenors used proxy groups that were different than the proxy groups used by the utilities.

22. The parties used different companies for their proxy groups and, at times, excluded companies from their proxy group when using the CAPM, RPM, and DCF financial models.

23. The parties used variations of the CAPM, DCF and RPM financial models to support their respective ROE recommendations.

24. Each party used different subjective inputs and variations of the CAPM, RPM and DCF financial models as a basis for their recommended ROEs.

25. A flotation cost adjustment to the financial models was rejected by the Commission in D.92-11-047.

26. Financial risk is tied to the utility's capital structure.

27. Business risk pertains to new uncertainties resulting from competition and the economy.

28. AB 1054 has substantially mitigated wildfire liability exposure as well as liquidity concerns.

29. With the adoption of AB 1054 there are no remaining significant unmitigated risks that warrant investor compensation through a higher ROE.

30. Regulatory risk pertains to new risks that investors may face from future regulatory actions.

31. SCE has an investment grade rating of BBB from S&P.

32. SDG&E has an investment grade rating of BBB+ from S&P.

33. SoCalGas has an investment grade rating of A from S&P.

34. PG&E has a non-investment grade rating of D from S&P because it is currently in Chapter 11 bankruptcy proceedings and is in default on its bond payments.

35. Quantitative financial models are commonly used as a starting point to estimate a fair ROE.

36. The average ROE authorized for electric and gas utilities in the United States in 2018 were 9.60% and 9.59%, respectively.

37. Two important components of the Bluefield and Hope decisions are that the utilities have the ability to attract capital to raise money for the proper discharge of their public utility duties and to maintain creditworthiness.

38. PG&E provided a comprehensive review of the ratemaking treatment for customer deposits.

39. The CCM is a beneficial mechanism for the Commission to employ.

Conclusions of Law

1. The consolidation of these applications does not mean that a uniform ROE should be applied to each of the utilities.

2. The legal standard for setting the fair ROE has been established by the United States Supreme Court in the Bluefield and Hope cases.

3. The capital structures proposed by SCE and PG&E should be adopted because they are balanced, attainable, and intended to support an investment grade rating and attract capital.

4. The capital structures proposed by SDG&E and SoCalGas should not be adopted because they do not sufficiently balance ratepayer interests with the intention to maintain an investment grade rating and attract capital.

5. The applicants' costs of long-term debt and preferred equity are reasonable and should be adopted.

6. SDG&E did not propose a cost of preferred equity, and it should be required to propose an updated cost of preferred equity through a Tier 2 Advice Letter submitted to the Commission's Energy Division.

7. Companies selected for a proxy group should have basic characteristics similar to the utility that the companies are selected to proxy.

8. Companies within a proxy group should not deviate from financial model to financial model.

9. PG&E has not substantiated that investment risks of its proxy group of non-utility companies is comparable to its proxy group of utility companies or to PG&E.

10. Value Line electric industry classifications should continue to be used in ROE proceedings where financial models require the use of a proxy group.

11. Companies within a proxy group should continue to be screened to ensure that the included companies have investment grade credit ratings, a history of paying dividends and are not undergoing a restructure or merger.

12. The financial modeling results should exclude flotation adjustments for the reasons set forth in D.92-11-047.

13. Although the quantitative financial models are objective, the results are dependent on subjective inputs.

14. It is the application of informed judgment, not the precision of quantitative financial models, which is the key to selecting a specific ROE.

15. Company-wide factors such as risks, capital structures, debt costs and credit ratings are considered in arriving at a fair ROE.

16. Debt equivalence should be considered along with other risks in arriving at a fair and reasonable ROE.

17. There should be no adjustment to the financial modeling results for other financial, business or regulatory risks because the financial modeling results already include those risks.

18. A test year 2020 ROE range from 9.80% to 10.60% is just and reasonable for SCE.

19. A test year 2020 ROE range from 9.65% to 10.45% is just and reasonable for PG&E.

20. A test year 2020 ROE range from 9.60% to 10.40% is just and reasonable for SDG&E.

21. A test year 2020 ROE range from 9.40% to 10.30% is just and reasonable for SoCalGas.

22. A test year 2020 ROE of 10.30% and rate of return (ROR) of 7.68% is just and reasonable for SCE.

23. A test year 2020 ROE of 10.25% and ROR of 7.81% is just and reasonable for PG&E.

24. A test year 2020 ROE of 10.20% and ROR of 7.55% is just and reasonable for SDG&E.

25. A test year 2020 ROE of 10.05% and ROR of 7.30% is just and reasonable for SoCalGas.

26. The CCM should be extended through the 2020 Test Year Cost of Capital Cycle.

27. PG&E has fulfilled its obligation to provide a comprehensive review of the ratemaking treatment for customer deposits, as directed in D.14-08-032, and the ratemaking treatment directed in that decision should remain in effect.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company's cost of capital for its test year 2020 operations is as follows:

	Capital Proportion	Cost Factor	Weighted Cost
Long-term Debt	43.00%	4.74%	2.04%
Preferred Equity	5.00%	5.70%	0.29%
Common Equity	52.00%	10.30%	5.35%
Return on Rate Base			7.68%

2. Pacific Gas and Electric Company cost of capital for its test year 2020 operations is as follows:

	Capital Proportion	Cost Factor	Weighted Cost
Long-term Debt	47.50%	5.16%	2.45%
Preferred Equity	0.50%	5.52%	0.03%
Common Equity	52.00%	10.25%	5.33%
Return on Rate Base			7.81%

3. San Diego Gas & Electric Company's cost of capital for its test year 2020 operations is as follows:

	Capital Proportion	Cost Factor	Weighted Cost
Long-term Debt	45.25%	4.59%	2.08%
Preferred Equity	2.75%	6.22%	0.17%
Common Equity	52.00%	10.20%	5.30%
Return on Rate Base			7.55%

4. San Diego Gas & Electric Company shall propose an updated cost of preferred equity through a Tier 2 Advice Letter submitted to the Commission's Energy Division no later than 30 days following the effective date of this Decision using the same conventional methodology for the calculating of the cost of preferred equity that the Commission has already approved.

5. Southern California Gas Company's cost of capital for its test year 2020 operations is as follows:

	Capital Proportion	Cost Factor	Weighted Cost
Long-term Debt	45.60%	4.23%	1.93%
Preferred Equity	2.40%	6.00%	0.14%
Common Equity	52.00%	10.05%	5.23%
Return on Rate Base			7.30%

6. The existing ratemaking treatment of customer deposits will continue to be in effect for Pacific Gas and Electric Company.

7. The Cost of Capital Mechanism shall continue to be in effect through the 2020 Cost of Capital cycle for Southern California Edison Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company.

8. Southern California Edison Company, Pacific Gas and Electric Company San Diego Gas & Electric Company, and Southern California Gas Company shall implement the revenue requirement changes authorized by this decision in their respective end-of-the-year consolidated revenue requirement Tier 1 advice letter filings, also referred to as Annual Electric True-Ups or Annual Gas True-Ups, for effective dates no earlier than January 1, 2020.

9. Application (A.) 19-04-014, A.19-04-015, A.19-04-017, and A.19-04-018 are closed.

This order is effective today.

Dated December 19, 2019, at San Francisco, California.

MARYBEL BATJER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners