Application No. 18-04-___
Exhibit PAC/200
Witness: Kurt G. Strunk

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Direct Testimony of Kurt G. Strunk

Return on Equity

April 2018

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ATTACHED EXHIBITS

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

A. My name is Kurt G. Strunk. I am a Director of National Economic Research Associates (NERA). My business address is 1166 Avenue of the Americas, New York, N.Y. 10036. I am filing testimony on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp).

I. QUALIFICATIONS

Q. Briefly summarize your professional experience.

A. Since the mid-1990s, my work at NERA has focused on strategic and corporate financial issues facing public utilities in the natural gas, oil, and electric power sectors. I have served as a testifying expert on public utility rate matters before federal, state and provincial regulatory commissions in the U.S. and Canada, and in a number of U.S. court proceedings. I have also served as a consulting expert in dozens of administrative law proceedings before energy regulators in North America, Europe, Australia, and Africa. I have served as an expert in over 50 rate cases.

My assignments frequently require that I determine the appropriate return on equity capital (ROE) for energy companies. I have calculated and supported required rates of return in traditional rate cases for regulated entities and in litigation and advisory work. I also write articles on cost-of-capital estimation and make presentations on the topic at industry conferences. My experience includes numerous assignments relating to the development and regulation of the power industry in California and the Western interconnection. As a result, I am very familiar with the market, regulatory, and legislative environment in which

PacifiCorp operates.

Prior to joining the Energy Practice, I was a member of NERA's Securities and Finance Practice. Exhibit PAC/201 contains a more detailed statement of my qualifications.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present my estimates of the cost of equity necessary to provide a fair and reasonable return for the equity owners of PacifiCorp. I recommend that the California Public Utilities Commission (Commission) use these levels of ROE to calculate PacifiCorp's revenue requirement in connection with the electric rates being applied for in this proceeding.

Q. Please explain, summarily, how you derive your estimate of PacifiCorp's cost of equity.

A. To arrive at the cost of equity, I apply well-established techniques to select a national proxy group of comparable companies and to estimate the expected equity return for those companies using the Discounted Cash Flow (DCF) model, Risk Premium models including the Capital Asset Pricing Model (CAPM), and the Comparable Earnings and Expected Earnings approaches. The application of established financial modeling techniques has for many years provided a direct and objective way of determining the fair return. In today's context, such modeling continues to be useful, but investors face unusual capital market conditions and the development of a fair return estimate presents challenges both to the financial analyst and to the finders of fact in proceedings like this one. Two factors complicate the otherwise prosaic application of these well-established techniques: the first is the persistence of central bank intervention in capital markets, which has created an interest rate environment that has no precedent in recent history; and the second is investor sentiment and concerns about the potential for a major correction.

In such a context, it is important to rely on multiple approaches for determining the cost of equity capital and to give less weight to approaches that yield results that fail to meet simple common sense tests. Consequently, I have taken extra steps to assure that the estimate of fair return is reasonably supported by multiple approaches and indicators of the expected returns available to investors from comparable investments. I rely upon multiple models and approaches and examine multiple indicators of risk and return from the capital markets.

Q. What is your recommendation for a fair return on equity for PacifiCorp?

A. As shown in Exhibit PAC/202, based on the analysis I performed for this filing, the fair return for PacifiCorp is 10.60 percent. The recommended 10.60 percent ROE is equal to PacifiCorp's existing allowed ROE and therefore represents no change in this rate, as it affects PacifiCorp's revenue requirement. This level of ROE falls squarely within the zone of reasonableness for the California operations of PacifiCorp. I have taken into account the following key factors in developing this recommendation:

- ROE model estimates that range from 8.37 percent to 12.10 percent;

- Rising interest rates during the rate effective period, reflecting the Federal Reserve's (Fed) recent interest rate increases, together with its intention to continue to raise short-term rates and to normalize its balance sheet through asset sales;
- Heightened volatility in the equity markets, reflecting greater risk and higher required returns;
- The need to assure credit quality throughout a period of large capital expenditures to facilitate grid transformation; as noted by credit rating agencies, PacifiCorp's shifting fuel mix from coal to renewables and the accompanying upsizing of capital expenditures raise uncertainty and risk for PacifiCorp; and
- Perceived risks identified by the investment community for electric utilities operating in California, including the increase in community choice aggregation (CCA) in California which is positioned to shift the roles of the incumbent utilities and heighten risks for their equity owners.

Adoption of my recommendation, updated as appropriate during the course of this proceeding, will provide appropriate compensation to PacifiCorp's owners—both for the time value of money and for the risks PacifiCorp faces—and appropriate protections for customers taking electric service. In sum, adoption of my recommendations will ensure that the rates for PacifiCorp meet the requirement that they be just and reasonable.

I will update my calculations during the course of this proceeding, and will be prepared to discuss any subsequent updates at hearing. I expect to perform this update in connection with the preparation of rebuttal testimony. The update will include a refresh of all inputs to the financial models used to estimate ROE.

Q. How is the remainder of your testimony organized?

A. Section 3 provides the regulatory and theoretical basis for my recommended cost of equity calculation. Section 4 provides an overview of the currently anomalous capital market conditions. Section 5 explains how I arrived at an appropriate proxy group from which to estimate cost of equity. Section 6 contains a description of the DCF models I rely upon, the CAPM and Risk Premium models, and the Comparable Earnings and Expected Earnings approaches, together with a summary of the results. Section 7 discusses the business and financial risks faced by PacifiCorp as compared to those faced by proxy group companies and explain how I value those risk differences. Section 8 addresses CCA. I describe the risks that incumbent utilities have faced during the transition to greater retail choice. Section 9 includes a summary of allowed returns available to other public utilities and a comparison of my model results to those benchmarks.

III. DESCRIPTION OF THE STANDARD AGAINST WHICH FAIR RETURNS MUST BE JUDGED

Q. On what regulatory and theoretical framework do you base your recommendation?

A. The Commission is charged with regulating utility sales of electric power in the state. The statute requires that utility rates and the terms and conditions of service be just and reasonable. A key tenet in the determination of just and reasonable rates is that owners of regulated companies must be afforded a reasonable opportunity to earn a fair return on their invested capital. Fair return is thus an essential component of a regulated company's cost of service.

The practice of determining "fair return" is guided by the landmark Supreme Court decisions in *Federal Power Commission et al v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield Water Works & Improvement Co. v. Public Service Comm'n*, 262 U.S. 679 (1923). A fair return must be sufficient to attract capital and must compensate investors at a level consistent with returns on investments of comparable risk. In *Bluefield*, the Supreme Court held:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.[1]

In *Hope*, the court found:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[2]

Rates of return that compensate investors for opportunity costs and permit utilities to attract capital are a cornerstone of regulatory practice in the United States.

Q. Does the manner in which fair return is determined in regulatory practice comport with economic and financial theory on cost of capital?

A. Yes. The legal standards for determining a fair rate of return for regulated utilities

[1] *Bluefield*, 262 U.S. 679, 692-3 (1923).
[2] *Hope*, 320 U.S. 591, 603 (1944).

comport with the theory established in the field of financial economics. Financial economists have long recognized that the cost of capital must be assessed recognizing the opportunity costs of foregoing alternative investments and current consumption.[3] Financial economics also recognizes that investors must be compensated for risk and that returns must be commensurate with the level of risk in order to attract capital. In this regard, regulatory practice and financial theory align well.

Q. Is the cost of equity capital directly observable?

A. No. It is not possible to observe the cost of equity directly in the capital markets. The return expectations of equity investors are not published directly in trade journals, as are some other financial data. They must be estimated or derived indirectly using financial models and the financial data that are made available to the public. In this regard, it is unlike the cost of debt, which anyone may directly observe from the coupon rates and market prices of long-term debt instruments issued by corporations.

Q. Must the cost of equity be assessed on a forward-looking basis?

A. Yes. The cost of equity can only reflect the forward-looking expectations of investors who demand compensation for the use of their money in risky investments. It is essential that the cost of equity capital be defined as a forward-looking concept.

Q. Please describe the risks that must be considered in assessing the cost of equity.

A. The cost of equity that investors demand is a function of the business and financial risks to which their capital is exposed. "Business risk" refers to the level of risk

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[3] *See* Brealey and Myers, *Principles of Corporate Finance* at 121, 544 (7th ed. 2003). *See also* Ross, Westerfield, and Jaffe, *Corporate Finance* at 167 (4th ed. 1996).

embedded in the business itself, while "financial risk" refers to risk arising from choices management makes regarding how the firm is financed. If, for example, the firm employs a high level of debt leverage in its capital structure, such leverage amplifies risk for the equity investor because the equity investor is a residual claimant, only entitled to the firm's cash flows after the debt capital providers have been paid.

Q. Did the principles for determining fair return in regulatory practice and those established by financial economics guide your assessment of PacifiCorp's cost of equity?

A. Yes. These principles guided my analysis and assessment of the cost of equity for PacifiCorp.

Q. Are the principles you describe also applied by the Commission?

A. Yes. In 2012, the Commission, in approving fair returns for the large investor-owned utilities in California, articulated its intent when implementing the fair return standard as follows:

> 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.[4]

[4] Public Utilities Commission of the State of California Decision 12-12-034, "Decision on Test Year 2013 Cost of Capital for the Major Energy Utilities," Dec 2012.

IV. CURRENT CAPITAL MARKET CONDITIONS

Q. The conditions following the 2008 financial crisis have been characterized as anomalous. What makes them so?

A. These capital market conditions are unique from a historical perspective. Following the financial crisis of 2008, the Fed held short-term interest rates at levels close to zero for eight years in a row. In the past two years, however, the Fed has begun to raise short-term interest rates steadily.

The establishment of very low interest rates for such an extended period represents a massive policy stimulus. But the Fed has also undertaken additional stimulus. After the 2008 crisis, the Fed undertook a bond-buying program, which had the effect of keeping long-term interest rates down. Although the Fed terminated its bond-buying program in 2014,[5] other central banks continue to purchase financial assets even today. As of February 2018, approximately 33 percent of all government bonds throughout the world are held by central banks. Prior to the Great Recession, approximately 14 percent of government bonds were held by central banks.[6] In these balance sheet expansions, central banks have even gone so far as to buy corporate bonds and equities.[7] For its part, the Bank of Japan has been a large buyer of Japanese stocks and has been on track to become the largest shareholder in companies in the Nikkei Index.[8] Since the financial crisis began, major central bank holdings

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[5] Board of Governors of the Federal Reserve System. (2014 October 29). Federal Reserve issues FOMC statement [Press release]. Retrieved March 5, 2017, from https://www.federalreserve.gov/newsevents/pressreleases/monetary20141029a.htm.
[6] "Santelli Exchange: Central bank balance sheets reach…" *CNBC*, 2018 February 5.
[7] "Central Banks Embrace Risk in Era of Low Rates," *Wall Street Journal*, Jan. 23, 2017.
[8] "The Bank of Japan's Unstoppable Rise to Shareholder No. 1." *Bloomberg*, August 14, 2016.

have more than tripled, rising from over $6 trillion in 2008 to over $19.5 trillion as of October 2017.[9]

The monumental policy interventions by the Fed and by central banks across the globe have had profound effects on financial markets. As a result of the Fed's policies, and those of other central banks, long-term interest rates—traditionally used by financial analysts to model investor return expectations—remain near all-time lows. At the same time, as demand for stocks has pushed equity prices up, dividend yields have fallen significantly since 2009, both for industrial firms generally and for utilities. I show this in Exhibits PAC/203 and PAC/204.

Q. What is the future outlook for capital markets during the rate effective period?

A. Investors in capital markets today continue to anticipate accommodative policy from central banks, leading to a continuation of the anomalous conditions and very low yields on government bonds. As noted above, recent activity by foreign central banks indicates a near-term continuation of interventionist policies, despite efforts by the Fed to normalize policy here in the United States, as discussed below. Yields on long-term treasuries remain extremely low from a historical perspective.[10] Equity prices have been driven up by demand for stocks.

Q. Is the Fed continuing with its plan to normalize interest rate policy?

A. Yes. The Fed first began to normalize in March 2016. The Fed implemented a 25

[9] Yardeni, Edward and Quintana, Mali. "Global Economic Briefing: Central Bank Balance Sheets." *Yardeni Research, Inc.*,December 5, 2017.
[10] *See*: Board of Governors of the Federal Reserve System (US), Memorandum Item: Securities Held in Custody for Foreign Official and International Accounts: Marketable U.S. Treasury Securities [WMTSECL1], retrieved from FRED, Federal Reserve Bank of St. Louis, accessed May 25, 2017, https://fred.stlouisfed.org/series/WMTSECL1.

basis point increase in the target federal funds rate in December 2016, a 25 basis point increase in March 2017, a 25 basis point increase in June 2017, and another 25 basis point increase in March 2018.

Jerome Powell has been confirmed as Janet Yellen's replacement as chair of the Fed. Powell has indicated that he will stick to the same monetary policy strategy that Yellen has charted, raising interest rates gradually over the next several years. It is expected that the Fed will raise interest rates a total of three times in 2018, three times in 2019, and two times in 2020.[11] Powell also acknowledged that beyond normalizing interest rates, "It's time for us to begin normalizing…the balance sheet," estimating that the bank will hold anywhere between $2.5 trillion and $3 trillion of debt in its portfolio over the next three to four years, representing a reduction of the current $4.5 trillion in investments in its portfolio.[12] As unprecedented US central bank buying of bonds and other securities was designed to artificially lower yields and spreads (thereby lifting asset prices), one can only expect central bank selling of those same assets to have the reverse effect on markets. The US central bank has entered the selling phase.

Q. How do capital market analysts believe that long-term treasury yields will evolve in the near future?

A. The long-term treasury yield forecast shows an expected rise. As shown in Exhibit

[11] Craig Torres, "Fed Lifts Rates, Steepens Path Through 2020 for More Hikes," *Bloomberg*, March 21, 2018, https://www.bloomberg.com/news/articles/2018-03-21/fed-raises-rates-steepens-path-of-hikes-as-outlook-strengthens.

[12] Donna Borak, "Jerome Powell says Fed likely to hike rates in December," *CNN*, Nov. 28, 2017, http://money.cnn.com/2017/11/27/news/economy/jerome-powell-senate-confirmation-hearing/index.html.

PAC/205, the median forecast for long-term treasury yields increases from 3.05 percent in Q1 2018 to 3.70 percent in Q4 2019. Thus, the base level of yields for treasury bonds, over which risky asset spreads are determined, is expected to increase. This, in turn, will have an effect on financial markets, as noted by Goldman Sachs, "Higher bond yields are likely to weigh on equities and reduce their buffer for shocks."[13]

Q. Is the prospect for heightened volatility a concern in today's market?

A. Yes. As shown in Exhibit PAC/206, volatility in the stock market, as measured by the VIX index, has recently spiked, and investors remain concerned over large swings in the underlying stock market. While standard measures of volatility remained unnaturally low over the course of 2017, in recent years the volatility index itself has exhibited unusual volatility. Reuters reports that "An analysis of intraday volatility across major equity, bond and currency markets shows that episodes of sudden, extreme market volatility has become more commonplace in the last two years, even though implied volatility has been contained."[14]

From a survey conducted by Natixis Investment Managers, 72 percent of institutional investors say they are surprised volatility has been so low for so long, and, as of late 2017, most did not think the trend would continue into 2018. Seventy-eight percent expect the stock market will be more volatile and 70 percent think the

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[13] See: "Why rising bond rates may be a threat to stocks." *CBS News*. March 31, 2017 and "Goldman says the Fed's Rate Hike Is Bad News For Stocks." *Fortune*. March 15, 2017.
[14] "A volatile calm - the paradox of 2016 financial markets." *Reuters,* December 22, 2016.

bond market will be more volatile in 2018.[15] Their predictions came true as volatility spiked in early February 2018.

This increase in volatility is a strong concern for investors. Vanguard produced its most cautious outlook in a decade based on concerns of more volatility, inflation, and dipping market performance next year. Vanguard sees higher U.S. wages or inflation causing investors to expect more aggressive rate normalization from the Fed, sparking more market volatility.[16] The Vanguard founder, John Bogle, recently characterized the volatility: "I have never seen a market this volatile to this extent in my career. Now that's only 66 years, so I shouldn't make too much about it, but you're right: I've seen two 50 percent declines, I've seen a 25 percent decline in one day and I've never seen anything like this before."[17]

Q. Please summarize how these current capital market conditions affect your cost-of-capital analysis.

A. The current capital markets can be characterized by unusually low levels of interest rates, intervention by global central banks, and heightened volatility. Low interest rates boost demand for stocks pushing their prices up and dividend yields down, which has resulted in DCF results that do not always square with other indicators of fair return. The normalization of central bank balance sheets will put pressure on

[15] Elizabeth Bartlett and Ted Meyer, "2018 Outlook: Institutional Investors Shrug Off the Volatility, Asset Bubbles and Fragile Markets they Expect Next Year, Natixis Survey Finds," *BusinessWire*, Dec. 5, 2017, http://www.businesswire.com/news/home/20171205006065/en/2018-Outlook-Institutional-Investors-Shrug-Volatility-Asset.

[16] Nico Grant, "Vanguard Warns More Volatility in 2018 May Hurt Equity Returns," *Bloomberg*, Dec. 4, 2017, https://www.bloomberg.com/news/articles/2017-12-04/vanguard-warns-volatile-2018-makes-firm-most-guarded-in-10-years.

[17] Thomas Franck, "Jack Bogle says he hasn't seen a market this volatile in his 66-year career," *CNBC*, April 5, 2018, https://www.cnbc.com/2018/04/05/jack-bogle-says-he-hasnt-seen-a-market-this-volatile-in-his-66-year-career.html.

capital market prices and is likely to push yields and required returns up. Further, the increase in market volatility indicates increased risk for equity investors. I consider these to be factors that suggest rising required returns during the rate effective period.

V. DEVELOPMENT OF AN APPROPRIATE PROXY GROUP

Q. Do you rely on a proxy group of comparable companies when applying the DCF and CAPM models?

A. Yes. To determine the cost of equity for PacifiCorp, I rely upon a proxy group of comparable companies in the same industry to gauge investors' return expectations for investments with corresponding risks. The use of a proxy group containing multiple companies helps to assure a stable, reliable and objective estimate of the cost of capital.

Q. What comparable companies do you employ for the California electric operations of PacifiCorp?

A. As shown in Exhibit PAC/207, my electric proxy group includes 25 companies: (1) ALLETE, Inc.; (2) Alliant Energy Corporation; (3) Ameren Corporation; (4) American Electric Power Company, Inc.; (5) CMS Energy Corporation; (6) Consolidated Edison, Inc.; (7) DTE Energy Company; (8) Duke Energy Corporation; (9) Edison International; (10) El Paso Electric Company; (11) Eversource Energy; (12) Fortis Inc.; (13) Great Plains Energy Incorporated; (14) IDACORP, Inc.; (15) NextEra Energy, Inc.; (16) OGE Energy Corp.; (17) PG&E Corporation; (18) Pinnacle West Capital Corporation; (19) PNM Resources, Inc.; (20) Portland General Electric Company; (21) Public Service Enterprise Group Incorporated; (22) Southern Company; (23) Vectren Corporation; (24) Westar Energy, Inc.; and (25) Xcel Energy

Inc. Similar to PacifiCorp, each of these companies has substantial electric utility operations.

Q. Did you consider including other Berkshire Hathaway Energy utilities in your electric proxy group?

A. Yes, I considered that possibility. However, data on how the capital markets price equity investments in those utility companies is not available. As a result, the well-established financial models that I use to develop ROE estimates for each member of the proxy group cannot be applied to the Berkshire Hathaway Energy utility subsidiaries.

Q. How did you arrive at this proxy group?

A. I used a series of screening criteria that allowed me to identify firms that have similar characteristics to PacifiCorp. The specific characteristics I sought to identify include:

i. **That a company is considered an "Electric Utility" by the Value Line Investment Survey.** This requirement simply establishes the initial universe of potential proxy companies.

ii. **That a company has a credit rating from Moody's or Standard & Poor's (S&P) that is comparable to that of PacifiCorp, *i.e.*, not more than one rating up or down.** I examined credit ratings so that the proxy companies selected are of comparable creditworthiness to PacifiCorp.

iii. **That a company has 10 quarters of constant or increasing dividends.** This criterion is necessary to assure that the DCF model functions predictably and yields robust results.

iv. **That a company has a positive five-year growth forecast.** Like the criteria above, this is necessary to assure that the DCF model, in its single-stage format, functions predictably, and yields robust results.

v. **That a company does not have a merger or other extraordinary activity within the past six months, significant enough to distort the DCF inputs.** This criterion is needed to assure that the DCF results are not biased by idiosyncratic event-driven stock price movements.

vi. **That a company operates primarily in regulated businesses.** I exclude companies whose operations are primarily unregulated because they do not meet a basic level of comparability. While having some unregulated interests is not sufficient grounds to exclude a company, firms whose businesses are predominantly unregulated do not make for suitable comparisons to PacifiCorp. To be included in the proxy group, a company must meet a threshold of having 50 percent of its revenues derived from regulated businesses.

vii. **That there is data available regarding a company to perform DCF analysis.** This criterion is needed because, of course, if the data is unavailable, the DCF model cannot be run. Some companies do not have sufficient analyst coverage for a consensus earnings forecast to be produced. Companies with fewer than two analysts covering their stock are not eligible for inclusion in the proxy group.

Q. Please describe how the screening criteria were applied.

A. I started with the 41 companies classified by Value Line as being in the electric utility industry. The application of the credit rating screen reduced the proxy group to 33 companies. Screening for companies with constant or increasing dividends and growth forecast resulted in the elimination of one additional company, bringing the group to 32. Two additional companies lacked five-year positive growth forecasts, reducing the proxy group to 30 companies. The merger and extraordinary event screen identified four additional companies for exclusion:

- Dominion Energy, Inc. (1), which plans to acquire SCANA Corporation for $14.3 billion.
- SCANA Corporation (2), for the same reason as above.
- Sempra Energy (3), which plans to acquire Energy Future Holdings Corp for $13.1 billion.
- Avista Corporation (4), which is in the process of being acquired by Hydro One Limited for $6.7 billion.

The elimination of the four merger-affected companies reduces the proxy group to 26 companies. Next, I eliminated one additional company, CenterPoint Energy, because its revenues were primarily generated from unregulated businesses outside of the electricity sector. All remaining companies, 25 of them, had data available to run the DCF model, and hence were adopted as the proxy group. This screening selection is shown in Exhibit PAC/207. As noted in this exhibit, the results of screens were only reported if a prospective proxy company passed all prior screens.

VI. DESCRIPTION OF EMPIRICAL MODELS AND RESULTS

DCF Model

Q. Please describe the DCF model that you employ.

A. The DCF model has in the past been the most commonly-used model in North American regulatory practice to determine the cost of equity for public utilities, although several regulators have recognized its shortcomings in the current market environment.[18] The DCF model is founded on a well-established principle in financial economics: *i.e.*, that the price of a given asset in a competitive market is the discounted stream of future cash flows it can produce.[19] Equity investments in public utilities produce cash dividends and capital gains. Hence, the DCF model attempts to estimate the dividends and capital gains that can reasonably be expected to accrue to equity investors, which are reflected first in current dividends and second in forecast earnings growth. The stream of expected dividends and growth—taken together with pricing for a utility's common stock established by competitive trading on a stock exchange—allows financial economists to calculate the implied discount rate at which investors evaluate future dividends and growth. Under the DCF model, the

[18] *See, e.g,*. the North Carolina Utilities Commission decision in Duke Energy Progress' most recent rate case in which that commission held that all of the "DCF analyses in the current market produce unrealistic low results." *In the Matter of Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, N.C. Util. Comm'n, Docket No. E-2, Sub 1142 Order at 85 (Feb. 23, 2018).
[19] For a discussion of the theory underlying the DCF model, please see: Myron J. Gordon, *The Investment, Financing and Valuation of the Corporation* (Homewood, IL: Richard D. Irwin Inc., 1962).

discount rate is the return that investors require for committing their capital as equity in the public utility corporations.

Q. Please describe the inputs to your DCF calculations for the proxy group companies.

A. I rely on the following inputs:

i. Common stock prices for proxy group companies, obtained from Bloomberg Finance LP.

ii. Current dividends, obtained from Bloomberg Finance LP and/or FactSet Data Systems.

iii. Forecast earnings growth rates, summarized by the Institutional Brokers' Estimate System (IBES) and obtained from Yahoo Finance and FactSet Data Systems.

iv. Estimated sustainable growth rates, using data obtained from Value Line.

The first two data sets are used to calculate the dividend yield, while the last two represent different ways of assessing investors' growth expectations. For my first method, I rely upon consensus forecasts for earnings growth. The second method is the development of a sustainable growth rate, reflecting the firm's retained earnings as well as its expected returns from the sale of new stock at a premium to book value. The sustainable growth inputs can be found in Exhibit PAC/208. My DCF analysis relies upon an average of the two results (consensus forecast and sustainable growth) when determining the ROE.

Q. Please explain how you use the stock price data and dividend information.

A. I calculate an average dividend yield for each proxy group company by aggregating the dividends earned over a 12-month historical time period divided by the average stock price during that period. I then convert the historical dividend yields to forward-looking dividend yields by multiplying by one plus the growth rate. The data used in my analysis covers the period through early-February 2018.

Q. Does the DCF model combine the dividend yields with the growth forecasts to arrive at a cost of common equity for the proxy group of electric utilities?

A. Yes. The DCF model is structured to evaluate the cost of equity as "yield" plus "growth". As noted above, the use of the historical stock prices, together with the most recent dividend per share payments, allows me to calculate the historic yield component, which I then convert to a forward-looking dividend yield by adjusting for one year of growth. As shown in Exhibit PAC/209, this yields an average cost of common equity for the electric utility proxy group of 8.37 percent.

Q. Do you have concerns over the use of the DCF model in the context of anomalous market conditions?

A. Yes. During this recent course of extraordinary monetary policy, DCF results have often been inconsistent with other indicators of required returns on equity. I, therefore, view them cautiously and compare them to other ROE metrics before giving substantial weight to them.

Q. Has the Federal Energy Regulatory Commission (FERC), which exclusively uses a proxy-group-based DCF to determine ROE, addressed the current anomalous market conditions and their effects on DCF results?

A. Yes. Anomalous capital market conditions have led the FERC to question the reasonableness of the assumptions and inputs to its formulaic DCF approach. The FERC has now stated that: "all methods of estimating the cost of equity are susceptible to error when the assumptions underlying them are anomalous."[20] To address potential errors in the proxy group DCF under current conditions, FERC developed an alternative measure of central tendency that focuses on the upper half of the range of estimated ROEs and that, in its judgment, resulted in a fair return.[21] Although the DC Circuit court has asked the FERC to detail the rationale for its approach, I have no reason to believe that FERC will make major changes to it.

Q. Using the FERC measure of central tendency, what are the resulting ROEs from your analysis?

A. Using the FERC's alternative measure of central tendency, the DCF model yields an expected ROE of 9.88 percent for the electric utility proxy group.

Q. Have you performed another version of the DCF model, the Yield-Plus-Growth (YPG) model?

A. Yes. The YPG model I employ is a form of the DCF model. It examines the two components of required return for the electric power industries as a whole.

[20] FERC Opinion No. 531-B, para. 50, *150 FERC ¶ 61,165*.
[21] FERC Opinion No. 531, *149 FERC ¶ 61,032*.

Specifically, it relies on the observed dividend yield for the industry (the yield component of the required return) and expectations of earnings growth (the growth component). When combined, these two data points offer an objective reading of investor expectations for the industry. As noted, the YPG estimate is, in essence, the DCF model applied to the industry.

Q. Why is the YPG model helpful in determining ROE?

A. It is helpful because it provides a transparent and relatively simple benchmark for return expectations for the electric power industry. It relies on highly visible inputs that influence investors' forward-looking expectations about rates of return for electric utilities.

Q. Please summarize the results of the industry YPG model.

A. As shown in Exhibit PAC/210, the industry YPG model yields an expected ROE of 12.10 percent for electric utilities.

CAPM and Risk Premium Models

Q. Please describe the Equity Risk Premium approach.

A. The Equity Risk Premium model is a build-up model that starts with the expected return on riskless assets and adds various premia to reflect the increasing levels of risk faced by equity investors. The additional premia added include a general stock market return premium, and in some cases an industry or size-specific premium.[22] My analysis relies upon two such models: the first is known as the CAPM, and the second the Risk Premium model. While these two models are

[22] *See, e.g.*, Ibbotson Associates, *Market Results for Stocks, Bonds, Bills and Inflation, 2011 Valuation Yearbook.*

similar in the sense that they both fall into the general category of equity risk premium models, they use different approaches and different data inputs to obtain an ROE estimate.

Q. Please describe the first model, the CAPM.

A. The CAPM starts with the expected return on riskless assets and adds a premium that is company-specific to reflect the risks faced by that company's equity investors. The degree of market risk embedded in an individual stock is measured by its beta. Technically, beta measures the level of correlation between the returns on a given stock and the returns on the broader market.[23] Investors in any given stock, therefore, should expect to earn a return equal to the return on riskless assets plus a premium that depends on beta, the degree of market risk associated with that particular stock. In equation form, the CAPM is represented as follows:

$$k_e = R_f + ß * (R_m - R_f)$$

Where:

k_e is the required ROE;

R_f is the current expected return on riskless assets;

ß is the degree of systematic market risk for the stock (correlation to the broader market);

$R_{m,}$ is the expected return on risky equity investments; and

(Rm - Rf) represents the premium required by investors in the stock market.

As noted, the CAPM can be viewed as a special case of the Equity Risk Premium model in which a company's equity risk premium is determined by the beta and the overall premium demanded by investors for holding stocks.

[23] The more volatile the return of a particular stock relative to the broader market, the higher the beta.

Q. How did you calculate the premium required by investors for holding stocks, a key input to the CAPM?

A. I calculate this premium (known as the "Equity Risk Premium" or "Market Risk Premium") as the difference between the expected return on the S&P 500 index and the yield on long-term U.S. treasury bonds. In equation form, the premium can be expressed as follows:

$$ERP = D/P * (1 + g) + g - R_f$$

Where:

ERP is the equity risk premium;
D/P is the market dividend yield;
g is the current analyst expected growth rate for the S&P 500;
R_f is the current expected risk-free return.

Exhibit PAC/211 presents this calculation.

Q. Are there other approaches to assessing this input?

A. Yes, financial analysts also assess market risk premia on a historical basis. They derive this by examining the actual historical performance of stock investments relative to the generally accepted measure of a risk-free return reflected in long-term (e.g., 20- or 30-year) government bonds.

Q. Why have you elected to rely on a forward-looking market risk premium?

A. I rely on the forward-looking premium because, in the current interest rate environment, the historical market risk premium does not always characterize investors' forward-looking return requirements as accurately as the forward-looking premium does. The spread between the risk-free rate and the required returns for holding equities has broadened as the Federal Reserve System has aggressively acted to keep interest rates at record lows and stimulate the economy. This is reflected in a relatively stable awarding of allowed returns to public utilities in the context of a rapid decline in treasury yields, the market's metric of the "risk-free" rate. As shown in Table 1 below, since 2006, the average allowed return for electric utilities has hovered in the range of 9.8 to 10.5 percent, while treasury yields fell 200 basis points and then started to recover, only to fall back again. If the market risk premium had been unchanged during this period, the allowed returns—which themselves are based on the capital market data put forth by public utilities and intervenors alike—would have declined as precipitously as the treasury yields did. They did not. A constant historical equity risk premium ignores the elevated cost of holding risky securities relative to the riskless security benchmark. The forward-looking premium thus provides financial analysts and the Commission with the most accurate gauge of investor demands in the current market environment, where required returns on equities have decoupled from treasury yields.

Table 1: Treasury Yields and ROE

Year	Treasury Yield (30-year)[24]	Electric Utility Allowed ROE[25]
2006	4.91	10.32
2007	4.84	10.30
2008	4.28	10.41
2009	4.08	10.52
2010	4.25	10.37
2011	3.91	10.29
2012	2.92	10.17
2013	3.45	10.02
2014	3.34	9.91
2015	2.84	9.85
2016	2.59	9.77
2017	2.90	9.74

Q. Please summarize your CAPM results.

A. As shown in Exhibit PAC/212, the CAPM model yields a range of returns on equity for the electric proxy group companies from 7.02 percent to 10.53 percent, with an average of 8.47 percent. I note that an important disconnect exists between the CAPM results and other indicators of comparable investment returns. As the FERC implicitly acknowledged in Docket No. ER14-500-000,[26] when such a disconnect exists, calibration to alternative benchmarks is needed in order to arrive at a fair ROE.

[24] Treasury yields obtained from the Federal Reserve's h15 release.
[25] Allowed returns obtained from Regulatory Research Associates, a division of SNL Energy.
[26] *See Order Accepting Tariff Filing Subject to Condition and Denying Waiver*, at 36, FERC Docket No. ER14-500-000 (Jan. 28, 2014).

Q. Turning now to the second model, the Risk Premium model, how does it differ from the CAPM?

A. I rely on the Risk Premium model to estimate a cost of equity estimate for the electric utility industry broadly, whereas my use of the CAPM model focuses on using observed capital market data to develop the cost of equity for the companies in the proxy group.

Q. Please explain the Risk Premium model.

A. The Risk Premium model uses the historical relationship between electric (and gas) utility returns and bond yields to predict the cost of equity today using the yields currently observed on bonds. I model this historical relationship by developing a least-squares regression analysis that uses the bond yield to explain the average allowed return for electric utilities as a function of the level of interest rates (as reflected in the yields on government bonds, A-rated utility bonds, and BBB-rated utility bonds). Specifying the model in this fashion takes account of the fact that the equity risk premium varies with the overall level of interest rates. My methodology tracks how the model has been applied by financial economists, as evidenced in the academic literature.[27]

Q. What are the results of your Risk Premium model?

A. The Risk Premium model indicates a cost of equity for electric utilities of on average 9.87 percent. As noted above and shown in Exhibit PAC/213, I rely on three different classes of bonds to assess the risk premium associated with electric

[27] *See* W. Carleton, W. Chambers and J. Lakonishok, *Inflation Risk and Regulatory Lag*, Journal of Finance, (May 1983). A similar approach is presented in R. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management (Spring 1986).

utility stocks: government bonds, A-rated utility bonds, and BBB-rated utility bonds. The 9.87 percent result reflects the average of the results for each class of bonds for electric utilities.

Comparable Earnings and Expected Earnings

Q. Have you performed a Comparable Earnings analysis?

A. Yes, I have. I analyzed the returns actually earned by utilities and industrial firms since 2002. The *Hope* decision establishes that a utility must be granted the opportunity to earn returns that are comparable to those earned by *unregulated* firms of similar risk. Consistent with *Hope*, the industrial firms selected for my analysis form an appropriate unregulated peer group for comparison purposes,[28] while the utilities group contains peers from the same industry.

Q. Please summarize the results of the Comparable Earnings analysis.

A. As shown in Exhibit PAC/214, the Comparable Earnings model yields an average ROE of 9.64 percent for the utility peers and 16.50 percent for the industrials. These earned returns are one of the many factors that influence investors' forward-looking expectations about rates of return.

Q. Have you performed an analysis of expected earnings for the proxy group?

A. Yes, I have. Exhibit PAC/215 presents this analysis.

Q. How does the expected earnings analysis differ from the comparable earnings analysis?

A. While comparable earnings is a backward-looking analysis that considers results

[28] *See, e.g.*, H. Roseman, Comparable Earnings and the Fair Rate of Return, Public Utility Law (ABA 1970).

obtained by comparable companies, the expected earnings analysis is based upon forward-looking projections. My expected earnings analysis summarizes investor expectations of the returns on equity that will be available to the proxy group companies in the future.

Q. What results do you obtain from the estimated earnings analysis?

A. The estimated earnings analysis indicates an average estimated ROE for the proxy group of 10.69 percent.

VII. BUSINESS AND FINANCIAL RISKS RELATIVE TO THE PROXY GROUP

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

A. In this section I describe at a high level the business risks of PacifiCorp and compare them to those of the proxy group companies to evaluate whether PacifiCorp has the same risk profile as the proxies.

Q. What are the basic types of business risks applicable to electric utilities?

A. Companies engaged in the generation, distribution and sale of electric power at retail face a variety of risks. These include risks traditionally faced by any regulated utility in North America (*e.g.*, the risk of prudence disallowance, the risk of regulatory lag, the risk that demand for service does not permit full recovery of costs, risk associated with general economic trends, interest rates and financial market conditions). As companies like PacifiCorp invest, they also face construction risk, contracting and litigation risk, and potential delays in bringing new plant into service. They face a material risk of future economic obsolescence for new plant that will go into rate base and be depreciated over an assumed useful life, which may or may not turn out to be the actual economic life.

Q. What specific risks are investors concerned about for PacifiCorp?

A. Analyses done by Fitch and Moody's ascribe several company-specific risks to PacifiCorp. PacifiCorp's shifting fuel mix from coal to renewables and the accompanying upsizing of capital expenditures create uncertainty and risk for the company. PacifiCorp currently derives 55 percent of its net load from coal and has spent much of the past several years investing in retrofitting its coal fleet. However, PacifiCorp now faces pressure to reduce the size of its coal fleet and is facing increasing renewable portfolio standards in several states. Consequently, PacifiCorp plans to retire 667 MW of coal by 2021 and 3,650 MW by 2036, and as proposed in this case, all coal-fired units will be fully depreciated by 2029. In parallel, PacifiCorp anticipates a major escalation in capital investment in renewables. PacifiCorp has increased its 2017-2019 capital budget by almost $1 billion from its prior three-year plan to fund the repowering of 905 MW of existing wind facilities and the addition of 1,100 MW of new wind capacity by the end of 2021.[29]

Another key risk and source of uncertainty identified by the investment community is the flat load growth in PacifiCorp's service territories, due to gains in energy efficiency and significant growth in the number of net metering customers. Because PacifiCorp recovers much of its fixed costs through variable (i.e., per kWh) charges, the uncertainty regarding future load levels and cost recovery poses significant financial risk.

[29] *See*, "PacifiCorp Credit Opinion," *Moody's Investor Service*, April 7, 2017. PacifiCorp has informed me that it revised its capital plan to incorporate investments above the levels indicated by Moody's Investor Service.

Q. How do these risks impact your recommendation for a fair rate of return for PacifiCorp?

A. Given PacifiCorp's need for new capital to finance the move to a cleaner fuel mix and its vulnerability to uncertain levels of future load it will be important that the Commission authorize a fair return that does not fall at the low end of the zone of reasonableness. A return at the low end of the zone of reasonableness would frustrate PacifiCorp's efforts to complete its capital program.

Q. Are there additional risks that PacifiCorp faces when applying for an authorized ROE in California?

A. Yes. The four largest IOUs in California—Pacific Gas and Electric (PG&E), Southern California Edison (Edison), San Diego Gas and Electric (SDG&E), and Southern California Gas (SoCalGas) (together the IOUs) —have a more favorable process for setting their cost of capital than PacifiCorp has. This is because the IOUs can adjust ROE as capital market conditions change, thereby reducing regulatory lag. In 2008, the Commission established a Cost of Capital Mechanism (CCM) to govern a new cost-of-capital application process for the IOUs. Under the CCM, the IOUs file a joint cost-of-capital application every three years separately from their general rate cases. For the years in which a new application is not filed, the CCM provides for the automatic adjustment of the IOUs' cost of capital based upon changes to prevailing utility bond rates. Following the most recent CCM adjustment, the IOUs were approved for the following returns on equity: PG&E – 10.25 percent, Edison – 10.30 percent, SDG&E – 10.20 percent, and SoCalGas – 10.05 percent, for an average of 10.20 percent. On the other hand, PacifiCorp can only apply for changes to its cost of capital in the same filing as its general rate case.

Q. Are there recent events that have heightened investor perceptions of risk for California utilities?

A. Yes. The impact of recent California wildfires have increased investor perceptions of risk for California utilities. While negligence or imprudence by an individual company ought not to increase investor perceptions of risk, the recent experience with wildfires raises an issue of business risk exposure that cannot be managed. On whether other California utilities face wildfire risk, Moody's emphasized the point with respect to Pacific Gas & Electric's pending situation, "<u>Even if found not negligent</u>, PG&E may be liable for several billions of dollars of damages."[30] The Moody's finding that a California utility potentially faces billions of dollars in liability even if the utility is not negligent illustrates the heightened risk investors face when investing in California utilities relative to investing in other utilities.

Q. Does your review of the business and financial risks facing PacifiCorp in California show less risk exposure than the proxy group companies?

A. No. I find that PacifiCorp faces a heightened level of risk relative to the companies in the proxy group. Because of its large investment plan, its near-term risks are amplified. The transition away from the stable fuel source of coal and the uncertainty in future levels of load, in particular, contribute to a unique risk profile that defies the notion that PacifiCorp faces lower risk. In addition, all of the

[30] "Moody's Sees Negative Credit Implications from CPUC Wildfire Ruling," *NGI's Daily Gas Price Index*, Dec. 6, 2017, http://www.naturalgasintel.com/articles/112663-moodys-sees-negative-credit-implications-from-cpuc-wildfire-ruling (emphasis added).

investor-owned utilities in California face heightened risks from wildfires and CCA. These risks are not present for the vast majority of proxy group companies. I detail the risks associated with CCA and the associated loss of retail customer loads in Section 8 below.

VIII. AGGREGATION AND CUSTOMER CHOICE

Q. Please describe CCA in California.

A. Governed by state statutes passed in 2002 and 2011 (AB 117 and SB790, respectively), CCA allows cities and counties to act as the load-serving entities for customers located within the city or county boundaries. The city or county still receives transmission and distribution service from the investor-owned utility, and the utility provides metering, billing, and customer service functions. Customers located within the city or county may opt out of participation in the program at no cost during the first sixty days. The procurement of power and the rates charged by the city or county are not regulated by the Commission.

Q. Is the scale of CCA a threat to incumbent utilities' business model?

A. Yes. Forecasts of aggregation in the coming years indicate that as much as 85 percent of loads currently served by investor-owned utilities could participate in the CCA program by 2020.[31]

Q. Does the investment community consider CCA to be a risk for incumbent utilities?

A. Yes. While Moody's characterizes the regulatory framework in California as

[31] Informal Comments of Southern California Edison Company, Pacific Gas & Electric Company and San Diego Gas & Electric Company on the October 31, 2017 California Public Utilities Commission (CPUC) California Customer Choice Project Workshop, November 28, 2017, page 6.

generally constructive, it notes the specific risks of CCA and other initiatives that pose challenges for incumbent investor-owned utilities.

> California also has a higher degree of political risk than most other jurisdictions in the US. The California Public Utilities Commission (CPUC) places a heavy demand on the utilities to carry out public policy goals and initiatives, such as reaching a 50% renewable portfolio standard by 2030. Many other ongoing policy initiatives such as storage mandates, electric vehicle infrastructure and community choice aggregation make it more challenging to maintain a consistently high level of reliability. These policy goals create a higher level of media attention and scrutiny and issues can quickly become contentious and litigious.[32]

Q. In practical terms, what risks do incumbent utilities face as a result of CCA?

A. CCA poses risks that are similar to those that arose in the context of sector restructuring and retail market liberalization. In California, these initiatives were undertaken by the Commission following the publication of its Blue Book in 1994. The standard formula for introducing retail choice typically includes the deregulation of the investor-owned utilities' power generation assets and full opening of the retail power marketing businesses, while preserving traditional regulation of the network functions (i.e., transmission and distribution) performed by the utilities.

Q. Please outline the key risks for incumbent utilities during the transition to CCA.

A. The biggest risk for incumbent utilities is that certain costs associated with the transition may not be recoverable. Examples of costs that may not be recovered

[32] "Rating Action: Moody's upgrades PG&E Corporation and Pacific Gas & Electric; outlook revised to stable," *Moody's Investors Service*, July 25, 2017.

include stranded generation costs and Provider of Last Resort (POLR) costs. I address each in turn.

Q. What are the stranded generation costs?

A. The stranded cost associated with an electricity generation asset is equal to the difference between the yet-unrecovered original cost base of the investment and the value of the asset in the competitive marketplace. It is that portion of the yet-unrecovered original investment that is “stranded” (i.e., cannot be recovered) under competitive pricing conditions. The value of the asset in a competitive marketplace is the present discounted value of the net cash flows produced by that asset.

Q. Are stranded generation costs generally recoverable?

A. In principle, yes. Because the generation investments were made by utilities in good faith, as part of the fulfillment of the obligation to serve their franchise customers, stranded costs have generally been considered recoverable under regulatory practice. However, experience shows that, despite the understanding that such costs are recoverable, utilities going through restructuring processes have faced significant challenges around the recovery of these costs and their measurement.

Q. Have you gathered evidence to demonstrate that stranded cost recovery risk is an important concern for investors?

A. Yes, I have. I gathered evidence from prior state restructuring initiatives.

Q. Please describe that evidence.

A. To provide an example of the type of concerns faced by equity investors, I refer to the Value Line Investment Survey, an independent subscription service covering U.S. equities. I examined the Value Line publications for utilities from summer and fall 1998, when many states were proceeding rapidly with the dis-integration of incumbent utilities and the introduction of competition at the retail level. Specific to stranded cost recovery risk, these issues of Value Line highlight the following concerns for utilities (emphasis added):

- **PECO Energy. "**Rate cuts are slated for 1999 and 2000. According to the restructuring settlement, PECO will lower retail tariffs by 8% next year and 6% the year after. A rate cap equal to the 1996 system-wide average (9.96 cents/kilowatthour) will be in effect through mid-2005. Higher bulk power sales might well partially offset the revenue reductions, though O&M cost actions, a smaller capital spending budget, competitive transition charges, and the issuances of low-cost asset securitization bonds should all provide support to the bottom line. **Even so, in light of the rate cuts, the fact that PECO will not recover 100% of its stranded cost and the certainty of increased competition, earnings may decline in 2000 to the $2.30-$2.40 a share level."**

- **PG&E.** "The utility faces a state ballot initiative in November. The ballot measure calls for utilities to reduce rates by 20% twice the cut provided for in August 1996 restructuring legislation. It also prohibits the recovery of nuclear-related stranded costs through the use of rate reduction bonds. **Passage of the initiative would require PG&E to write off about $2 billion to $3 billion in generation-related assets."**

- **Northeast Utilities.** "The company's utilities are preparing for competition. Connecticut Light & Power (CL&P) will soon submit an industry restructuring plan with state regulators. In June, the utility filed for a 1% (or $21 million) rate cut, effective September 28th. (Rates were also lowered by 2.4% in July through a fuel clause adjustment.) This action will move it closer to a legislated 10% reduction, which is to be in place by 2000. The Western Massachusetts Electric Company (WMECO) has already filed a restructuring plan with state authorities. As part of that plan, WMECO will divest fossil and hydro generation and securitize its nuclear assets; proceeds will go to trim debt. Massachusetts rates will fall by about 10% ($35 million - $40 million) this year. A public referendum next month on industry restructuring, however, could disrupt the overall process.

  Important issues have yet to be resolved in New Hampshire. **The Public Service Company of New Hampshire (PSHN) subsidiary is in**

court fighting the implementation of a state restructuring order that provides for inadequate stranded cost recovery. A federal court has temporarily stayed the order. PSNH is also asking regulators to refrain from ordering a sizable rate cut. Management is working to settle these issues.

Though timely, this equity is too risky for conservative investors."

- **Texas Utilities.** "Stranded costs are a matter of concern. TXU's filing with the state commission indicated potential stranded cost of $2 billion. This figure would probably drop somewhat if retail competition is delayed beyond the expected 2001 date, since the company would have more time to reduce costs. But a final decision on stranded costs rests with the state legislature. This body failed to enact a law governing these costs when it last met in 1997, and it doesn't convene again until next year. **We think whatever law is passed will result in heavy asset write-offs."**

- **Sempra Energy.** "SDG&E has already gone through the regulatory restructuring process and should be able to recover its stranded costs (especially if it receives a premium when it sells its gas-fired plants.) There are two uncertainties of note, however. First, SDG&E has filed for electric and gas rate hikes under a new PBR mechanism, but intervenor groups are proposing electric rate decreases. **Second, a ballot measure, if enacted this fall, could overturn the state's regulatory restructuring law. That could force Sempra to take an after tax charge of as much as $400 million and could reduce 1999 earnings by $50 million."**

- **PEPCO.** "In its restructuring filing, PEPCO has identified about $600 million in stranded costs, including, purchased power contracts, generation, and regulatory assets. The company has petitioned for a competitive transition charge, which would be applied to all ratepayers from 2000 to 2010; tariffs would be capped from July 1, 2000 to January 1, 2004. PEPCO's plan also calls for shopping credits for customers who choose alternative power suppliers offering cheaper electricity. The MPSC is scheduled to rule on the plan in October, 1999; PEPCO will likely submit a revised filing –to address any of the regulators' concerns – one month later. At this time, we do not believe that the commission or the state legislature will impose requirements that would have a severe, negative impact on the company's long-term earnings performance."

- **PP&L Resources. "**PP&L has settled its regulatory restructuring case with the Pennsylvania commission. The utility wound up with a better order than it was originally granted (causing us to raise our 1999 share-earning estimate by $0.20), but the decision was still severe. **Although PP&L will be able to recover 76% of its stranded costs over an 11-year period, it had to take a write-off of $5.66 a share.** This charge (excluded from our earnings presentation) was largely associated with the

Susquehanna nuclear plant, but it also included write-downs of two coal plants that will be sold or closed. In addition, PP&L will institute a one-year, 4% ($90 million) rate reduction in 1999. The order includes an incentive for customers to choose alternative energy suppliers. What's more…PP&L has cut its dividend and will buy back some stock. The board of directors has reduced the quarterly dividend by 40% to $0.25 a share. The payout ratio was too high at a time when business risk is increasing (especially for a utility such as PP&L that intends to remain in power generation). Now, the directors will target a payout ratio of 45%-55%. For the benefit of those investors who want high income, PP&L established a Dutch auction tender offer (financed through borrowings) for up to 7 million shares at $24.50-$27.00 a share, which was scheduled to expire today. As a result of the write-off and the tender offer, PP&L's common equity ratio will fall to the low-30% range. We don't recommend this stock."

- **Pinnacle West.** "Retail electric competition in Arizona will commence in 1999. In early August, Arizona's Corporation Commission (ACC), which regulates the state's investor-owned utilities, approved plans to phase in competition between retail electricity suppliers, over two years, starting January 1, 1999. At that time, 20% of each utility's ratepayers would be granted the right to choose their energy supplier. All customers will have this prerogative by January 1, 2001.

  Recovery of stranded costs, the key near-term issue, has yet to be settled. The ACC has also established that it will allow the affected utilities a "reasonable" opportunity to recoup stranded costs, provided that every attempt to mitigate has been made. At this point, we believe that regulators will not provide for total recovery of Pinnacles' stranded costs, which in turn could result in rate cuts and/or asset write-offs.

  These shares are ranked to underperform the market in the coming year."

Q. What are the consequences of these investor concerns?

A. As evidenced in the Value Line analyst commentary, many utility stocks were falling out of favor with investors given the heightened risks associated with restructuring, and particularly with the prospect of inadequate stranded cost recovery. When stocks fall out of favor, it means that the companies need to offer more attractive returns to entice investors. In the simplest terms, the heightened risk perceived by investors raises the cost of capital.

Q. Are you aware of other states where legislative or regulatory action put full recovery of stranded costs in jeopardy?

A. Yes, that was the case in New Mexico. Legislation passed in 1999 provided for the recovery of stranded costs, but within the broad range of 50 percent to 100 percent of the estimated total. Recovery above 50 percent would only be permitted if it did not trigger rate increases for domestic and other small users. Public Service Company of New Mexico at the time estimated its stranded costs (excluding nuclear decommissioning costs) to be almost $700 million and that, of this total, it may be able to recover about $525 million.

Q. What are POLR costs?

A. Where a CCA exists, the POLR is the supplier designated to serve customers who do not procure generation services from the CCA. The POLR also serves customers in jurisdictions that have not chosen to aggregate their customer loads. POLR costs reflect the expenditures incurred to buy power on behalf of customers taking service under the POLR rate. To the extent the POLR responsibility falls on the incumbent utility, it can pose large cost-recovery risks. In other states pursuing greater choice for customers, several utilities were unable to recover the full costs associated with mandated provision of POLR services.

Q. How are POLR issues relevant to CCA in California?

A. The California utilities are currently the POLRs. As the state's CCA programs grow, incumbent utilities will serve a smaller and smaller fraction of the load in their service territories. In comments submitted to the Commission, Southern California Edison, Pacific Gas & Electric and San Diego Gas and Electric noted:

> [T]he Joint Utilities remain the Providers of Last Resort (POLRs) should any customer choose to return to bundled service, or should any CCA or ESP decide to cease service either to a single customer or all of its customers, and also have a universal obligation to serve all customers. The State must carefully consider the implications of this regulatory framework in light of the forecast potential departure of up to 85% of the Joint Utilities' retail load for "customer choice" options in the near future. POLR structures, risk mitigation approaches, and compensation should be researched and evaluated.[33]

Q. What risks does an incumbent utility with mandated POLR responsibilities face?

A. In fulfilling its duties as a POLR, an incumbent utility faces a wide variety of commercial, regulatory, and legislative risks, not the least of which is that the utility will incur costs to buy power on behalf of its POLR customers and will not be allowed to reflect those costs in a timely fashion in POLR rates. Failure to reflect competitive POLR costs on a timely basis can cause significant harm to the financial integrity of the provider of last resort.

Q. How important are the regulatory and legislative risks of deferral or disallowance?

A. Disallowance and deferral risks are paramount. Typically, the purchased power supply costs for a utility are many times larger than the after-tax earnings for transmission and distribution operations. The scale of the POLR cost relative to the wires businesses means that even a deferral or disallowance that is small relative to the total cost of POLR supply can have grave effects on a utility's credit

[33] Informal Comments of Southern California Edison Company, Pacific Gas & Electric Company and San Diego Gas & Electric Company on the October 31, 2017 California Public Utilities Commission (CPUC) California Customer Choice Project Workshop, November 28, 2017, page 6.

and ability to raise capital. When I studied this for other utilities, I found that non-recovery of 20 percent of fuel and purchased costs could have the effect of wiping out more than half of the earnings for the entire wires-only enterprise. From the perspective of the electric distribution business, this would imply the loss of an even higher percentage of after-tax earnings.

Q. Have these POLR risks materialized for incumbent utilities in other states that pursued restructuring?

A. Yes. The experience in Maryland offers a good example of the risks for incumbent utilities and their customers arising from a mandated POLR responsibility. In Maryland, problems arose when the utilities transitioned from the historic generation rate that had prevailed prior to restructuring to market-based generation rates. Upward trends in the wholesale price of power led to increases in POLR rates for residential customers that would have been politically untenable. In this context, the Maryland Public Service Commission ordered the deferral of POLR costs. For Baltimore Gas & Electric (BGE), the deferral amounted to over $600 million, which in turn led to multi-notch credit downgrades. In addition to the $600 million deferral, BGE has faced the following financial losses and risks arising from its mandated POLR responsibilities:

- Over $90 million in non-recovery of POLR-related cash working capital costs due to the delayed resolution of Case 9221, a contentious docket addressing the methodology for determining POLR-related cash working capital revenue requirements. This docket was opened in 2009 and not resolved until 2017.

- The imposition of $187 million in customer bill credits associated with the resolution of outstanding POLR cost recovery disputes through a Settlement Agreement executed in 2008.

- Denial of recovery of the return component of POLR revenue requirements for residential POLR service for ten years, as mandated by Maryland Senate Bill 1.
- Disallowance by the Maryland Public Service Commission of $4.1 million in administrative costs required to securitize the deferral of POLR costs.
- The automatic deferral of future POLR rate increases in excess of 20 percent, mandated by Senate Bill 1, and potential disallowance thereof.

Importantly, there was no finding of imprudence by the incumbent utility for the denial of recovery of the costs noted above. Additionally, other events have created risk but have not led to under-recoveries or deferrals for the incumbent utilities in Maryland. Such risks are manifest, for example, in the introduction by the state legislature of multiple bills that would have changed the nature of the incumbents' POLR obligations without necessarily assuring cost recovery for prudently incurred costs. Such events underscore the uncertainties and risks surrounding POLR cost recovery.

Q. Is the existence of financial difficulties for the incumbent utility POLR provider unique to Maryland?

A. No, it is not. Illinois utilities faced a similar crisis when transitioning to a restructured sector. Again, the movement away from the unbundled generation rate of the incumbent utility to the use of a market-based generation rate caused similar problems. When the POLRs agreed to defer purchased power costs, they were subject to credit downgrades, which ultimately raised costs for customers.[34] Reuters released an article on October 5, 2006 entitled "S&P cuts ComEd's debt

[34] *See* "S&P cuts ComEd's debt rating," *Reuters,* October 5, 2006.

rating – may cut to junk," noting:

> In response to the prospect of state legislation extending a rate freeze, which would lead to billions in purchased power deferrals for the Illinois utilities, S&P noted the following: "[w]e will continue to lower the ratings if, in our opinion, the likelihood of legislation extending the rate freeze increases. **If rate freeze legislation is passed, we will lower ratings on the Illinois utilities into the B category."** (Emphasis added)

The Illinois utilities subsequently resolved their POLR risk through the transfer of procurement responsibility to the Illinois Power Authority and statutory language entitling the utilities to full cost recovery.

Q. How have credit ratings agencies viewed the risk of providing POLR service?

A. Credit rating agencies identify recovery of POLR costs as a significant credit consideration for electric distributors that retain a POLR obligation. Importantly, investor perspectives on the adequacy of cost recovery arrangements can change rapidly. Taking again the example of Maryland, the rating agencies have at times viewed the utilities as having proper regulatory arrangements in place. However, they were quick to downgrade the utilities as the regulatory situation in Maryland deteriorated during 2006. A positive view of BGE had been articulated by S&P as late as December 2005:

> What largely drives BGE's above-average business risk profile (a score of '3' on Standard & Poor's Rating Services' 10-point scale with '1' being the strongest) are the attractive features of Maryland's regulatory regime that minimize BGE's energy procurement risk.[35]

When higher wholesale market prices began to affect BGE's prospective

[35] "Summary: Baltimore Gas & Electric Co.," *Standard & Poor's*, December 5, 2005, pp. 1-2.

standard offer service prices in late 2005 and early 2006, pressure to defer a portion of these purchased power costs led Fitch in April 2006 to downgrade BGE's then-parent, Constellation Energy Group. Fitch cited BGE's uncertain prospects for cost recovery, stating that "[g]reater regulatory and legislative uncertainty in Maryland" was a key credit concern.[36]

> On April 11, 2006, Fitch Ratings downgraded Constellation Energy Group's (CEG) senior unsecured and issued default ratings to 'BBB+' from 'A-.' The rating downgrade reflected the anticipated credit deterioration of subsidiary Baltimore Gas and Electric Company (BGE) and the increased uncertainty in Maryland as a result of legislative and regulatory developments.
> . . .
> CEG's lower rating also incorporates increased uncertainty regarding the timeliness of BGE's energy cost recovery going forward, particularly if commodity costs remain high or increase in subsequent years.

By June 2006, the regulatory situation in Maryland had become generally chaotic and unpredictable. On June 22, Senate Bill 1, which phased in BGE's standard offer service rates, was vetoed by Governor Ehrlich,[37] only to be overridden by the legislature.[38] On July 11, 2006, citing significantly increased regulatory risk and adverse regulatory actions, Moody's downgraded BGE's senior unsecured credit rating to Baa2 from A3 and placed BGE on a negative ratings watch.[39] Moody's explained:

> The rating outlook for BGE is negative, reflecting a difficult and uncertain regulatory environment and exposure to market prices for power beginning mid-2007.

[36] "Credit Analysis: Constellation Energy Group," *Fitch Ratings*, May 24, 2006.
[37] Letter to the President, Governor Robert L. Ehrlich. June 22, 2006.
[38] Regulatory Research Associates, Focus Note – Maryland: June 23, 2006.
[39] "Moody's Downgrades Baltimore Gas & Electric," *Moody's Investor Service*, July 11, 2006, pp 1-3.

> . . .
> The downgrade of BGE's ratings reflects Moody's belief that the utility's financial performance will be significantly weaker for at least the next 18 months, due to substantial regulatory deferral of recovery of sharply higher costs of purchased power. Under the current regulatory environment, BGE's cash flow coverage of interest and debt is expected to fall to levels that would be more consistent with a low Baa rating in 2006 and 2007. The increase in the expected amount of cost deferrals since the last Moody's rating action will result in lower cash flow from operations for the next two years and higher debt balances for a longer period.[40]

Moody's cited specific regulatory and legislative actions:

> The expected amount of cost deferral has increased as a result of the rate mitigation plan imposed upon the company through Senate Bill 1, which was passed during a special session of the Maryland General Assembly. The downgrade also takes into account the financial effects of "give backs" by BGE that would be mandated under Senate Bill 1 over the next ten years and the significant increase in BGE's regulatory and legislative risk profile.[41]

Q. What lessons do the experiences of incumbent utility POLR providers in Maryland and Illinois hold?

A. On balance, these experiences underscore the risks faced by the incumbent utility POLR. They demonstrate that the implementation of customer choice can be a highly politicized process where decisions are taken in the legislature that preclude a full and prompt pass-through of POLR costs and compromise the financial integrity of the utility. The deferral of purchased power costs can force the POLR into a negative cash flow position and ultimately increase the cost to customers. The downgrades that accompanied the deferrals in Maryland and Illinois

[40] *Id.*
[41] *Id.*

demonstrate this.

As the Commission is well aware, a disconnect between power purchase costs and retail generation revenues also beset the California utilities following restructuring in the late 1990s.

Q. Did fundamental developments in wholesale power markets exacerbate the challenges faced by incumbent utilities during the restructurings of the late 1990s and early 2000s?

A. Yes, they did. A tightening in supply conditions in gas and power commodity markets led to increases in the cost of supplying generation service that dwarfed the competition-driven cost savings that most stakeholders were anticipating from restructuring. The push for restructuring in the first place had come from large customers seeking to access wholesale power markets where short-term prices were quite low owing to an extended period of excess supply and low fuel prices. As those conditions tightened, commodity power prices rose and no supplier—incumbent or new entrant—could offer price reductions to customers. In this context, lawmakers found it politically difficult to permit the full and timely pass-through of increases in commodity power costs, to the detriment of utility investors and ultimately customers.

Q. Could such a scenario play out again in California?

A. Yes, a similar fact pattern could plausibly develop in the coming years. Many fundamental factors—increases in output from renewables, demand reductions from energy efficiency, abundant and inexpensive natural gas—have put downward pressure on wholesale power prices. Changes in fundamentals could lead to tighter market conditions and the need for commodity-driven rate increases that are challenging to implement in the context of a restructuring that is intended to lower prices. The incumbent utilities in California could find themselves, once again, in the throes of a highly politicized customer choice process with inadequate recovery of prudently incurred costs.

Q. How have you evaluated the effect of CCA programs on the cost of capital?

A. I have used the experience from past state restructurings to evaluate the effect on cost of capital for incumbent utilities during the transition to a customer choice model. Specifically, I note the occurrence of credit rating downgrades resulting from the realization of associated risks. Active as an advisor on utility restructuring, I myself observed that equity price volatility for utilities going through the process of enhancing choice at the retail level, another sign of heightened risks. I account for these factors when making my ROE recommendation.

Q. How did credit rating agencies' view the restructurings of the 1990s and early 2000s?

A. I previously discussed the multi-notch downgrades that occurred in connection with the lack of full and timely recovery of POLR costs. In addition, the credit rating agencies followed the development of stranded cost recovery prospects closely. In California, the uncertainty surrounding stranded cost recovery led to negative ratings watches for the investor-owned utilities there.[42] This underscores the heightened risks faced by utilities undergoing similar processes and

[42] *See*, "S&P Revises California Electric Outlooks," *Standard & Poor's*, December 20, 1996.

demonstrates how ratings analysts incorporated those heightened risks into their ratings process, leading to higher costs of capital for the affected utilities.

IX. COMPARISON TO ALLOWED RETURNS

Q. Are returns granted to public utilities in other jurisdictions relevant to this proceeding?

A. Yes. The returns allowed by state regulators can influence investor expectations for investments in public utilities in the United States. An examination of the average rate of return granted to investors in public utilities is therefore useful to provide context to my recommendation.

Q. What levels of returns have state regulators awarded to public utilities recently?

A. As shown in Exhibit PAC/216, ROE awards in 2016 and 2017 for electric utilities ranged from 8.40 percent (for a distribution utility) to 11.95 percent (for a utility in Juneau, Alaska), with the average state-awarded ROE for the electric utility industry being 9.77 percent in 2016 and 9.74 percent in 2017.

Q. Is your ROE recommendation of 10.60 percent consistent with the range of observed authorized ROEs in other jurisdictions?

A. The range of allowed returns for vertically-integrated utilities like PacifiCorp tends to fall in the range of 9.5 percent to 10.5 percent. The ROE that I recommend appropriately falls just above that range. That the recommendation falls slightly above the range is grounded in three important facts: (1) that the interest rate environment has changed and yields are expected to increase during the rate effective period; (2) that PacifiCorp is undertaking a major capital investment program to facilitate grid transformation; and (3) that California is facing unique changes to its retail electric markets. Furthermore, it is important to note that the range of allowed returns is only one benchmark. The other analyses I perform also support my ROE recommendation of 10.60 percent.

Q. Have you compared your recommended return to FERC-authorized ROEs?

A. Yes. I show this comparison in PAC/216. Although business risk differences exist between the PacifiCorp business at issue in the instant proceeding and the companies to which those ROEs apply, these returns authorized by FERC provide yet another benchmark as returns available to equity investors in similar businesses.

Q. Does this conclude your direct testimony?

A. Yes.