A COST OF CAPITAL AND CAPITAL MARKETS PRIMER FOR UTILITY REGULATORS

April 2020

This publication was produced for review by the United States Agency for International Development. It was prepared by the National Association of Regulatory Utility Commissioners.

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Project Title:	A Cost of Capital and Capital Markets Primer for Utility Regulators
Sponsoring USAID Offices:	Energy Division, Office of Energy & Infrastructure, Bureau for Economic Growth, Education, and Environment (E3)
Cooperative Agreement #:	AID-OAA-A-16-00042
Recipient:	National Association of Regulatory Utility Commissioners
Date of Publication:	April 2020
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National Association of Regulatory Utility Commissioners

This publication is made possible by the generous support of the American people through the United States Agency for International Development (USAID). The contents are the responsibility of the National Association of Regulatory Utility Commissioners (NARUC) and do not necessarily reflect the views of USAID or the United States Government.

Primer Table of Contents

Acknowledgements

This Primer was developed in partnership with the National Association of Regulatory Utility Commissioners (NARUC) with the generous support of the United States Agency for International Development (USAID). This Primer is one in the series of various primers on cost-reflective tariffs and will be incorporated into a larger comprehensive guide on tariff settings, the Tariff Toolkit.

About the Author

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John obtained the Chartered Financial Analyst (CFA) designation in 1993, and continues to participate in the CFA Continuing Education Program while participating as a member of the CFA Institute and the CFA Society of Chicago. He served on the Board of the Society of Utility and Regulatory Financial Analysts (SURFA) from 1998 to 2008.

John served as a member of the National Association of Regulatory Utility Commissioners and its Committee on Gas, Committee on Consumer Affairs, and Subcommittee on Pipeline Safety during 2011-2016, the United States Department of Transportation Technical Hazardous Liquid Pipeline Safety Standards Committee during 2014-2016, and the Gas Technology Institute Public Interest Advisory Council during 2013-2016. He earned an MBA with a concentration in Finance from Michigan State University.

<u>List of Acronyms</u>

ROE – Return on Equity
ROR – Overall Rate of Return
WACC – Weighted Average Cost of Capital
DCF – Discounted Cash Flow
CAPM – Capital Asset Pricing Model
USoA – Uniform System of Accounts
GAAP – Generally Accepted Accounting Principles
FASB – Financial Accounting Standards Board
EPS – Earnings per Share
BVPS – Book Value per Share
FERC – Federal Energy Regulatory Commission

1. Introduction

With the support of the United States Agency for International Development (USAID) – Energy Division, Office of Energy & Infrastructure, the National Association of Regulatory Utility Commissioners (NARUC) has undertaken the task of developing a Cost Reflective Tariff Toolkit. This toolkit is intended to constitute several short practical primers that can be used by utility service regulators in countries with emerging economies to design rates that are based on actual cost of service and to effectively engage the public and key stakeholders in the decision-making process.

1.1. Objective

The objective of this primer is to help utility regulators around the world understand the capital markets and estimate the cost of capital, which is one of the components of effective cost-based ratemaking and developing cost-reflective tariffs.

1.2. Scope

This primer focuses on describing the capital markets and a set of pathways that regulators in countries with emerging economies may want to consider when estimating the cost of capital for use in determining the utility revenue requirement in ratemaking. This set of pathways is based on U.S. utility regulators' practices in estimating the cost of capital. Furthermore, the pathways include some observations to incorporate regional differences between the U.S. and countries with emerging economies.

1.3. Organization

This primer is organized as follows:

Section 2 provides a capital markets overview.

Section 3 provides a cost of capital overview.

Section 4 describes the capital structure components.

Section 5 describes the cost rates of debt and preferred stock.

Section 6 explains cost of common equity methodologies.

Section 7 summarizes how the preceding concepts are combined to estimate a utility's weighted average cost of capital.

Section 8 concludes with final remarks.

2. Capital Markets Overview

Utilities are required to raise capital from investors in order to provide safe, reliable, and affordable service to customers. Utility service is provided through investments in infrastructure that is constructed to last for multiple decades, which makes utilities among the most capital-intensive industries.

Investors supply capital to a utility with the expectation of earning a return. Investors require a return on an investment in relation to the risk of that investment. Low-risk investments require relatively low rates of return and high-risk investments require relatively high rates of return.

There are two primary types of capital: debt and equity. A debt investor essentially lends debt capital to the utility and expects to receive periodic interest payments and the return of principal at the end of the life of the debt security. In contrast, an equity investor acquires stock which represents an ownership interest in a utility and expects to receive periodic dividend payments and stock price appreciation upon selling the stock. In general, an equity investment is considered of higher risk than a debt investment.

Both debt and equity securities are traded in the capital markets. Capital markets are global, with investments competing against alternatives across the world on a risk-adjusted basis with capital funds readily flowing to investments that provide attractive risk-adjusted returns. Although alternative capital investments are evaluated by investors on their individual merits and risk metrics, securities issued by entities in developed economies generally exhibit some characteristics that are considered less risky than securities issued by entities in emerging economies. Developed countries may have greater access to the capital markets than emerging economies, particularly during times of illiquidity and capital market turbulence, such as global financial crises or global pandemics.

It is estimated that there are 60 major global stock exchanges[1] where common shares trade with a market capitalization of $78 trillion[2], approximately 41% in North America, 20% in Europe, and 33% in Asia.[3] Debt is also traded, but less often on formal exchanges. The global corporate debt market has been estimated at $135 trillion.[4]

It is not possible to directly observe the decision-making and thought processes of debt and equity investors, but it is possible to observe financial publications that are publicly available, including rating agency reports and equity sell-side analyst reports. Rating agencies are important because the credit ratings that they place on debt securities both reflect and influence the decision-making and thought processes of debt investors. Likewise, equity sell-side analyst reports are important because they both reflect and influence the decision-making and thought processes of equity investors.

2.1. Debt Capital Markets

Publicly-issued debt securities generally have several financial characteristics including a principal amount, coupon rate, maturity date, and issuance costs and premium or discount that are amortized over the life of the debt. The risk of debt is generally assessed by credit rating agencies. Globally, there are three prominent rating agencies - Moody's Investor Service ("Moody's"), Standard & Poor's Global Ratings ("S&P"), and Fitch Ratings ("Fitch"). Several small regional rating agencies exist and have a significant presence in certain geographic regions. This primer will focus on the big three global rating agencies because they control about 85% of the global credit rating market.

Moody's, S&P, and Fitch take business and financial risk into account when establishing credit ratings on utility debt. A key business risk for utilities is regulatory risk. The role of the rating agencies is to provide debt capital markets participants with an independent, objective, and forward-looking opinion of creditworthiness based on fundamental analysis including quantitative and qualitative factors. The rating

[1] Jeff Desjardins, "All of World's Stock Exchanges by Size," February 16, 2016.

[2] Ron Surz, "Most Expensive In World, But U.S. Economy Is Not The Most Productive," April 2, 2018.

[3] Jeff Desjardins, "All of World's Stock Exchanges by Size, February 16, 2016.

[4] Ron Surz, "Most Expensive In World, But U.S. Economy Is Not The Most Productive," April 2, 2018. The author estimates global total capitalization of $213 trillion. The global corporate debt market is the difference between total capitalization of $213 trillion and equity market capitalization of $78 trillion, or $135 trillion.

agencies assign a letter rating such as A, B, or C to debt securities that indicates the agencies' evaluation of the relative risk of a debt issuer's ability to meet its financial obligations to make required interest payments and pay back the principal in a timely manner. The ratings implicitly measure the probability of default. Letters closer to the front of the alphabet indicate higher levels of creditworthiness and a lower probability of default.

When a change in credit quality is perceived, the rating agencies will change the ratings up or down, thereby upgrading or downgrading the debt. The rating agencies' investment grade ratings are "AAA" or "Aaa," followed by "AA" or "Aa," then "A," then "BBB" or "Baa." The rating agencies also use a "+" or "1" designation to indicate a rating in the high portion of a rating category, and "-" or "3" designation to indicate a rating in the low portion of a rating category.

Every rating beneath "BBB" or "Baa" is considered sub-investment grade, junk, speculative, and high-yield, with the associated debt carrying significantly higher probability of default along with higher interest rates. Because utilities are capital-intensive and are required to provide service to customers regardless of capital market conditions, utilities generally target an investment grade credit rating at a minimum. Utilities often issue securitized debt that is backed by a pledge of specific assets that can achieve a slightly higher credit rating than otherwise for the utility's un-securitized debt.

The rating agencies have similar but not identical ratings methodologies for utilities. Moody's provides a particularly well-described example. Moody's utilizes a four-factor scorecard to assess utility risk. Factor 1 is Regulatory Framework and contributes 25% of the risk assessment with sub-factors of Legislative and Judicial Underpinnings of the Regulatory Framework and Consistency and Predictability of Regulation. Factor 2 is Ability to Recover Costs and Earn Returns and contributes another 25% with sub-factors of Timeliness of Recovery of Operating and Capital Costs and Sufficiency of Rates and Returns. As a result of Factors 1 and 2, 50% of Moody's risk assessment is directly tied to the regulatory environment. Factor 3 is not directly related to regulatory risk. Additionally, Factor 4 is Financial Strength, significantly based on cash flow metrics, and it contributes another 40%. The Financial Strength factor cash flow metrics are also significantly influenced by the regulatory environment. As a result, regulatory risk impacts well over half of the Moody's scorecard factors for utilities.

2.2. Equity Capital Markets

The risk of equity investments is assessed by all equity investors but especially by professional investment analysts at large institutional investors. Utility equity analysts are focused on researching utilities to pick winning and losing stocks and to achieve attractive risk-adjusted returns. Buy-side analysts make stock investment decisions, invest client funds, and have their performance evaluated by the return that they achieve relative to a benchmark. Typically, buy-side analysts work at asset managers, institutional investors, and hedge funds.

By contrast, sell-side analysts publish research reports with stock recommendations, market their services to buy-side investors, and have their performance evaluated by their clients, the buy-side investors. Typically, sell-side analysts work at investment banks, commercial banks, stockbrokers, and boutique research firms. As mentioned previously, it is not possible to directly observe the decision-making and thought processes of buy-side analysts that are making the actual investment decisions, but sell-side analyst reports both reflect and influence the decision-making and thought processes of buy-side equity investors.

Similar to utility debt investors, utility equity investors expend considerable effort assessing risk. There are many types of risk that investors consider. Risk falls into two primary categories: business risk and financial risk. Business risk is the risk associated with the variability of operating income and cash flows due to the fundamental nature of the firm's business, including sales volatility and operating expense uncertainty. In contrast, financial risk is the risk associated with the variability of earnings available for common stockholders due to the introduction of financial leverage, or capital components other than common equity, such as debt and preferred stock, into the capital structure.

For utilities, one of the most important types of business risk is regulatory risk. Regulatory quality impacts are assessed by investors when judging a utility's risk. Investors evaluate regulatory risk by understanding the regulatory climate because it is an important component of assessing risk and determining the value at which they are willing to transact on investments in regulated utilities. Equity investors form opinions about regulatory risk through meetings with company management and regulators and reviewing research reports as well as sell-side analyst reports because regulatory climate is significantly impactful on utility equity valuations.

2.3. Investor Risk Evaluations are Important to Utility Customers

The risks faced by utility investors are important to utility customers because risks to investors get reflected in the capital costs to the utility which are ultimately paid for by customers. Regulatory risk as perceived by investors impacts the availability and cost of capital. When investors perceive higher risk, the corresponding costs of debt and equity increase. If investors are less willing to provide capital, capital is less cost-effective for customers. For example, rating agency downgrades generally result in higher interest rates on newly-issued debt securities. A utility downgrade would place upward pressure on the embedded cost of debt, as new long-term debt securities are issued at higher interest rates. Additionally, a utility's cost of equity would increase as investors require a higher rate of return to compensate for additional risk.

Customers benefit by having a financially stable utility that has the earnings and cash flow sufficient to attract equity and debt on reasonable terms, and the resulting ability to provide safe, reliable, and affordable utility service. Receiving a reasonable authorized ROE and capital structure from regulators is an important contributor to financial stability. The customer benefits that result from being served by a financially healthy utility outweigh the illusory short-term "benefits" of a negative regulatory climate that heightens regulatory risk.

The level of authorized ROE and the ability to earn the authorized ROE through an appropriate capital structure used for ratemaking and tariff-setting are important considerations for investors' evaluation of regulatory quality and risk. Regulatory lag may lead to an earned ROE that falls short of the authorized ROE, thus negatively impacting investors' evaluation of regulatory quality and risk.

Regulators are charged with balancing the interests of investors and customers. Utility management has a fiduciary responsibility to deploy investors' capital productively. Investors recognize the importance of regulatory and stakeholder relationships and expect utility management to provide safe, reliable, and affordable service to customers in order to preserve and enhance the value of their invested capital. In many ways, the interests of investors and customers are aligned and not in conflict and can become more aligned through regulatory policy. Regulators are more effective at serving customers when they harness investors' desire to provide capital rather than constrain it.

3. Cost of Capital Overview

For a utility, a fair rate of return must be provided to investors and must be included in the revenue requirement in order to adequately cover the cost of doing business in ratemaking and tariff-setting. Fundamental financial concepts demonstrate that the fair rate of return to use in ratemaking for a utility is its cost of capital in order to achieve the proper balance between customers and investors. This overall fairness equation follows:

$$ROR = WACC$$

Where ROR = Rate of Return; and

WACC = Weighted Average Cost of Capital.

The Weighted Average Cost of Capital (WACC) is a fundamental financial concept that is widely used in the financial community by investors, investment bankers, academics, and corporate financial professionals. The WACC is also widely used by utility regulators and is integral to conventional cost of service ratemaking in developing the revenue requirement.

If the authorized ROR is set equal to the WACC, investors will provide capital with the expectation of receiving an adequate return. If the authorized ROR is set at a level lower than the WACC, the utility will be unable to raise capital at a reasonable cost and ultimately may be unable to raise sufficient capital to meet customer demands for service. Therefore, it is in the best interests of customers that the authorized ROR be set equal to the WACC.

The WACC approach is based on an analysis of the capital structure and the cost rates of the individual capital components as follows:

$$WACC = D/C \times K_d + E/C \times K_e$$

where WACC = Weighted Average Cost of Capital;

D = Total debt;

E = Total equity;

C = Total capital = total debt plus total equity;

K_d = the cost of debt; and

K_e = the cost of equity.

The debt, equity, and capitalization variables of the WACC equation are explained in Section 4. The cost of debt and cost of equity variables of the WACC equation are explained in Sections 5 and 6.

4. Capital Structure Components

All sources of investor-supplied capital are typically included in the capital structure. Investor-supplied capital includes long-term debt, short-term debt, preferred stock, and common equity. Typically, most utilities have long-term debt and common equity outstanding, while only some utilities have short-term debt and preferred stock outstanding. For ratemaking purposes, sometimes non-investor-supplied capital such as deferred taxes or customer deposits also is included in the capital structure rather than being treated through the rate base calculation, but that is beyond the scope of this primer.

Long-term debt can consist of mortgage bonds, debentures, convertible debt, bank loans, and municipal bonds and is generally reflected in the capital structure at its principal amount adjusted for the unamortized balance of issuance costs and discount or premium. To match the costs with the time period that the rates and tariffs will be in effect, it is possible to project the long-term debt that will be outstanding at a future balance sheet date by reflecting new issuances and maturities. Equity can consist of both common equity and preferred stock.

Short-term debt can consist of bank loans and commercial paper. Short-term debt, if it exists on the balance sheet, can be included or excluded in the capital structure as a matter of regulatory practice. Short-term debt is often used by utilities to finance construction and meet working capital needs in the short-run until it is replaced with long-term financing. Some regulators will exclude short-term debt with the view that it is temporary and will eventually be replaced with long-term capital. Other regulators will include short-term debt if the utility appears to employ it routinely on an ongoing basis.

Investor-supplied capital is recorded on a utility's balance sheet. A well-developed Uniform System of Accounts will ensure that debt and equity are accurately recorded on the balance sheet. The debt and preferred stock accounts on the liability side of the balance sheet are relatively straightforward with debt and preferred stock recorded based on issuance amount.

The common equity account on the balance sheet represents total assets minus total liabilities and generally covers the accounts of common stock, paid-in capital, retained earnings, and treasury stock. The common stock and paid in capital amounts generally result from stock issuances and the treasury stock amount generally results from stock that has been bought back by the company from investors. Besides obtaining new capital by issuing debt and equity, a utility can internally reinvest earnings not paid out as dividends and grow the retained earnings account.

Investors recognize that accounting principles, standards, and procedures, including Generally Accepted Accounting Principles ("GAAP") promulgated by the Financial Accounting Standards Board ("FASB"), ensure a level of consistency in the calculation of the common equity account that makes it easier for investors to analyze and extract useful information from financial statements. Utility investors recognize that a Uniform System of Accounts ("USoA") provides requirements that ensure additional consistency in the calculation of the book value of common equity. A USoA enhances uniformity, comparability, accuracy, reliability, and consistency for reporting, cross-company benchmarking comparisons, rate regulation, rate studies, cost-of-service studies, depreciation studies, market oversight, and financial audits. Although part of an investment analyst's duty is to scrutinize the financial statements, the existence of GAAP and the USoA provide a solid foundation for calculating the book value of common equity.

One of the primary issues when determining the capital structure for ratemaking purposes is the corporate level at which to measure the capital structure. The capital structure is typically measured at the corporate level at which the utility actually interfaces with the capital markets. Some utilities participate directly in the capital market and have a capital structure disciplined by the capital markets.

Actual capital structure ratios are generally used for a utility that has market-traded stock and/or debt directly issued to investors. Utilities that are subsidiaries of parent companies may interface with the capital markets at the parent level instead. If so, that parent capital structure can be considered for ratemaking purposes. However, parent companies may have significant non-utility operations of different risk that may render the use of the parent company capital structure inappropriate.

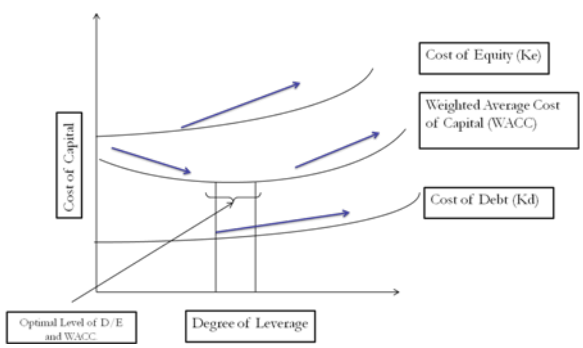
Hypothetical capital structures can be useful if the utility and/or the parent does not have an interface with the capital marketplace or the capital structure ratios are difficult to determine or significantly deviate from standards of comparison. But before considering the use of a hypothetical capital structure, it is worthwhile to explore optimal capital structure theory.

Utility management's goal is to manage the capital structure such that the WACC is minimized. Financial theory indicates that an optimal capital structure range exists that will minimize the WACC, but, in practice, it is very difficult to pinpoint optimal capital structure ratios with any degree of accuracy. To begin with, academic references about optimal capital structure are relatively vague and do not offer any empirical evidence to pinpoint one. In the real world practical corporate finance environment, academic theoretical references are interesting and may be thought-provoking, but do not provide a useful tool to fine tune a company's capital structure.

A utility management must be permitted latitude, discretion, and flexibility in managing capital structure ratios. Since there is no practical methodology to pinpoint theoretically optimal capital structure ratios, targeted ratios can only be broadly conceptualized. Appropriate ratios may shift over time as capital market conditions or business risk characteristics change. Additionally, the timing of upcoming issuances and maturities may influence the capital structure ratios because both the size and frequency of issuances are affected by the relative cost-effectiveness of various issuance increments.

Given these practical considerations, capital structure ratios cannot be deemed to be inappropriate unless the ratios greatly diverge from sound industry practice and cause a lack of financial flexibility that may lead to higher overall costs. The WACC curve is shaped like a very shallow dish such that large variances in capital structure ratios lead to minimal change in overall costs, as demonstrated in the following graph:

WACC Curve



As increasing financial leverage shifts the weight from common equity to lower cost debt, it also increases both the cost of debt and the cost of common equity. In practice, these offsetting impacts cancel each other out over a wide range of capital structure ratios, so hypothetical capital structures that micro-manage a utility's capital structure ratios by a 1% or 5% increment offer minimal opportunity to actually reduce the WACC.

Despite these challenges, it is possible that a utility's capital structure can deviate so significantly such that a hypothetical capital structure is appropriate. One way to think about this is the 80%/20% rule. If a capital structure contains more than 80% common equity, for instance 100%, hypothetical capital structure ratios can be imputed to reduce the common equity ratio down to 80%. On the other hand, if a capital structure contains less than 20% common equity, for instance 0% or below, hypothetical capital structure ratios can be imputed to increase the common equity ratio up to 20%.

As a result, financial theory and practice indicate that a regulator has little to gain by attempting to micro-manage capital structure ratios unless they significantly deviate from relevant standards of comparison. If accurate book value information is unavailable or unusual circumstances prevail, it may be appropriate to deviate from using a book value capital structure and instead use a market-value capital structure.

5. Cost Rates of Debt and Preferred Stock

Under conventional cost-of service regulation, the costs of debt and preferred stock are generally straightforward calculations and synched with the level at which the capital structure is determined. For ratemaking purposes, the cost rates of long-term debt and preferred stock are embedded cost concepts. Under certain circumstances including when a market value capital structure is used, it may be appropriate to deviate from using embedded cost rates and instead use incremental cost rates of long-term debt and preferred stock.

Debt generally has a contractually-stated fixed interest rate. Preferred stock generally has a contractually-stated fixed dividend rate. Short-term debt, such as bank loans or commercial paper, generally has a floating interest rate that changes periodically. In addition to the interest or dividend payments, utilities typically must recover incurred issuance costs related to the issuance of each long-term security that gets amortized over the life of the security.

Long-term debt typically is issued in terms of 5, 10, 20, or 30 years. At any given point in time, a utility typically has a variety of long-term debt issues of many vintages on its balance sheet. The cost rate of long-term debt is usually calculated as the average embedded interest rate (adjusted for the amortization of issuance costs and discount or premium) for all outstanding long-term debt securities as of the balance sheet date that is typically synched with the end of the test year. To match the costs with the time period that the rates and tariffs will be in effect, it is possible to project the long-term debt embedded cost rate that will be in effect at a future balance sheet date.

Preferred stock has generally not been issued prolifically by utilities in recent years. However, there may be some older-vintage outstanding preferred stock on the balance sheet. The embedded cost of preferred stock calculation is handled in much the same way as the embedded cost of long-term debt. The embedded cost rate of preferred stock is calculated as the weighted average dividend rate (adjusted for issuance costs) of all outstanding preferred stock issuances as of the balance sheet date that is synched with the end of the test year. To match the costs with the time period that the rates and tariffs are in effect, it is possible to project the preferred stock embedded cost rate that will be in effect at a future balance sheet date.

The cost of short-term debt has an identifiable interest rate that generally floats over time. The interest rate periodically re-sets according to an associated formula. It is possible to use the current interest rate on short-term debt as the cost of short-term debt or forecast the interest rate that will apply in the future according to the formula.

If deferred taxes are included in the capital structure rather than deducted from rate base for ratemaking purposes, they are generally included at zero-cost given their nature as a zero-cost loan from the governmental taxing authority.

6. Cost of Common Equity

Setting the authorized base ROE equal to the cost of equity is integral to conventional cost of service regulation. The cost of common equity is measured based on investors' required return on common equity. This equity fairness equation follows:

$$ROE = k_e$$

Where ROE = return on equity; and

K_e = the cost of equity.

Generally, common equity investors expect to achieve a return through common dividends and stock price appreciation. An equity investor receives no contractually obligated interest or dividend rate but receives dividends as declared at the discretion of the company's Board of Directors.

The cost of equity cannot be observed and must be estimated with forward-looking market-based financial models. As a result, cost of equity estimation is often the most controversial ratemaking issue in utility rate cases.

This cost of common equity section will focus primarily on estimating the cost of common equity for companies in mature economies. It may also be possible to directly estimate the cost of common equity for companies in emerging economies. These financial models are applicable in any currency. However, a useful technique to estimating the cost of equity in emerging economies is to base it on cost of equity estimates for companies in mature economies. One technique to accomplish this is described in the following CAPM section.

When estimating the cost of equity for a utility, the market-based financial models can be applied directly to the utility if it is traded on a stock market and has quoted stock prices. But often, the utility does not have stock traded on a stock market as a separate entity and thus, there is no way to directly observe the value that investors place on it. The utility may be a subsidiary of a parent company or an untraded privately-owned entity that does not have the data available to apply the financial models.

Occasionally, the parent company of the utility may be market-traded and may serve as an appropriate proxy for the utility but most parent companies have operations of different risk than the utility. The frequent solution is to select a proxy group of market-traded companies. The proxy group can include regulated utilities or unregulated companies of comparable risk that may have similar credit ratings or similar risk metrics or be in the same geographical region as the subject utility. Proxy group selection can involve a significant amount of analysis. The financial models are then applied to the companies in the proxy group and results are aggregated for the group through averaging. The resulting average cost of equity estimate for the proxy group serves as an estimate for the subject utility's cost of equity. The identification of proxy groups can be especially challenging in developing countries.

An example of the proxy group selection process from Federal Energy Regulatory Commission ("FERC") Opinion No. 531 in Docket No. EL11-66-001 is included in Appendix A. In this opinion, the FERC established the authorized ROE for a group of U.S. electric transmission companies that were non-market-traded subsidiaries and thus had no direct stock market data available. The FERC developed a proxy group of 38 companies by screening the universe of 49 national market-traded electric utilities listed in the *Value Line* financial publication for the availability of the desired market data and used credit rating risk screens of "A" to "BBB-" from S&P and "A1" to "Baa3" from Moody's. The credit rating screen eliminated four companies that were deemed outside the credit rating band of the subject group of transmission companies, while a dividend payment screen removed one, a mergers and acquisitions activity screen knocked out three, and a low-end outlier test cut three companies. FERC then determined cost of equity estimates for the 38 proxy companies resulting in an ROE zone of reasonableness of 7.03% to 11.74% with a midpoint of 9.39%, as shown in Appendix A. It is important to note that, for various reasons, FERC concluded that the authorized ROE should be set not at the midpoint of the proxy group, but at the 75th percentile of the zone of reasonableness, or 10.57%.

6.1. The Value of Using Multiple Financial Models

The goal of all cost of equity models is to capture the realities of the capital marketplace and each model does so from a different perspective. Because these financial models are simplifications of the real world, the ROE results are estimates rather than exact discernments of ultimate truth. Ideally, the model results will corroborate each other but may not in practice. Different estimates resulting from different models can usefully frame, bracket, or define a range or zone of estimates.

As context to investors' use of these models, it is important to note that: 1) the end goal of equity investors when using financial models is to make buy/sell equity investment decisions based on valuation; 2) the cost of capital estimation process is thus not the end goal of investors, but an intermediate step; 3) because the end goal of utility regulation is to determine the ROE based on the cost of equity, it is sometimes easy to conjecture that cost of equity estimates are an end goal of investors when they are not; 4) the cost of capital estimation process facilitates the equity valuation process of investors; 5) the models and inputs that investors actually use are unobservable and not publicly revealed; 6) investor consensus valuations in the marketplace are observable as stock prices; and 7) by combining cost of equity models that investors are known to use with data that investors are known to access along with observed market values, it is possible to back into cost of capital estimates that investors may be using in aggregate. In this context, an appropriately balanced set of financial models that are diverse, thorough, and reasonably comprehensive can be useful.

Moreover, investors are cognizant of model risk and measurement errors that can result from financial models in general. Model risk is the risk that a model used to simulate a real-world situation will fail to represent the real phenomenon that is being modeled. Model risk and measurement errors can include simplifications within the model, poor choice of inputs, measurement challenges, inaccurate estimates, flawed analyses, or user errors. There is no single cost of equity model that is best in all circumstances.

Investors, investment bankers, and corporate financial professionals use multiple models when evaluating the cost of equity. Likewise, it is desirable for regulators to also use multiple models when evaluating the cost of equity.

6.2. Discounted Cash Flow Model

The Discounted Cash Flow (DCF) approach is based on the fundamental financial concept of the time value of money and provides a conceptually correct and straightforward approach for determining the cost of equity. The DCF equation is commonly expressed as:

$$k_e = D_1/P_o + g$$

where K_e = the cost of equity;

D_1 = the dividend per share in time period 1, or the next period after the current period;

P_0 = the current stock price per share; and

g = the expected dividend growth rate.

The DCF model is based on the expectation that investors will receive cash flows over time that consist of a dividend yield that grows over time. The DCF model implies that the value of an asset is the expected cash flow generated by that asset, discounted by investors' required rate of return. Specifically, the market value of common stock is equal to the present value of the expected stream of future dividends. The dividend yield is generally the less controversial part of the calculation while the growth rate can be more controversial. It is necessary to determine the current dividend yield and growth rate simultaneously.

Dividends are typically declared and paid quarterly but raised annually. The dividend in the next annual period is sometimes estimated as the most recent quarterly dividend multiplied by 4, and sometimes estimated as the next anticipated quarterly dividend multiplied by 4. If the utility does not pay dividends, the DCF model is inapplicable.

The DCF model can be implemented annually or quarterly. For convenience, the DCF model is typically implemented on an annual basis because required rates of return are generally expressed on an annual basis, even though dividends are typically declared and paid quarterly. The quarterly DCF model may provide slightly more accurate modeling of expected cash flows, but is also more complex. For purposes of this primer, the annual DCF model will be highlighted.

The current stock price should be timely and generally is measured by a recent spot price at the time the ROE analysis is being performed, or an average of recent stock prices during the period of time the ROE analysis is being performed, generally a couple week to several months.

The DCF method requires a growth rate that reflects the long-run dividend growth rate expectation of investors. It is necessary for an analyst to develop a long-run dividend growth rate that is based on sound financial concepts and a certain amount of subjectivity. The expected growth rate that investors use is not directly observable, but there are estimates of expected growth available from sell-side analysts and investment advisory services.

In the long-run, expected dividend growth is a function of expected earnings growth. There are some sources of five-year expected dividend growth but more sources of five-year expected earnings growth. One commonly-used alternative is to use the five-year expected earnings growth rate as a proxy for the long-run expected dividend growth rate. Another option is to break out the long-run expected growth into discrete stages of growth through the use of a multi-stage DCF model.

6.3. Capital Asset Pricing Model

The Capital Asset Pricing Model (CAPM) approach is based on the theory that the required rate of return for a given security is equal to the risk-free rate of return plus a risk-adjusted risk premium. Financial theory presents the CAPM relationship as:

$$k_e = R_f + B_j \times (R_m - R_f)$$

where k_e = the cost of equity;

R_f = the risk-free rate of return;

R_m = the expected return on the market portfolio;

B_j = the measure of risk for stock j, or beta; and

$R_m - R_f$ = the market risk premium.

In order to implement this model, it is necessary to estimate the risk-free rate of return, the market risk premium, and the appropriate company-specific risk measure or beta. While the risk-free rate is generally observable, the primary challenge of the CAPM approach arises in the estimation of the market risk premium and the beta.

The risk-free rate concept is the yield on a security that has no risk. Of course, no security specifically meets the no-risk requirement. But in the United States, the yield on 20-year or 30-year long-term U.S. Treasury securities is often used as the risk-free rate. U.S. Treasury securities are considered to be virtually free of default risk because of the U.S. government's fiscal and monetary authority. U.S. Treasury securities are rated "AAA" by the credit rating agencies. Other countries that carry a "AAA" rating include Germany, Canada, Australia, Switzerland, Denmark, the Netherlands, Norway, Sweden, and Singapore.

The risk-free rate must be timely and generally is measured by a recent spot yield at the time the ROE analysis is being performed, an average of recent yields during the period of time the ROE analysis is being performed, published forecasts of yields, or forecasted yields from the futures markets.

The market risk premium is the difference between the expected return on the market portfolio and the risk-free rate, and represents the premium that the average-risk stock is expected to earn above the risk-free return. The market portfolio is usually defined as a broad stock market index such as the S&P 500. The market risk premium can be estimated by performing a DCF analysis on the market portfolio compared to the current risk-free rate or by observing the historical relationship of stock market returns to the returns on U.S. Treasury securities.

Beta is a company-specific risk metric that measures the risk of a specific stock in relation to risk of the market portfolio. Beta is widely recognized by the financial community as a measure of risk in a portfolio context. The beta relationship is generally identified through a regression analysis over a multi-year period. Betas are calculated and published by investment advisory services. A beta of 1.0 indicates a risk level equal to the market average risk level. A beta greater than 1.0 indicates a risk level greater than the market average risk level. Similarly, a beta less than 1.0 indicates a risk level less than the market risk level. Most utilities have a beta less than 1.0.

The CAPM method is particularly adaptable for estimating the cost of equity in an emerging economy through incorporation of a country risk premium. A country risk premium is the additional return that an investor demands to compensate for the higher risk of investing in a country with higher geopolitical and macroeconomic risks such as political instability, higher recession and inflation risks, sovereign debt burden, impact of currency fluctuations, and adverse governmental regulation. The country risk premium is generally higher for emerging economies than for mature economies.

Estimated country risk premiums are based on the relative spread between sovereign bonds, credit ratings, default spreads, and the relative volatility between equity markets. Various sources exist for estimating country risk premiums. Dr. Aswath Damodaran, Professor of Finance at the Stern School of Business at

New York University, is known for his country risk premium research and is one of the most notable sources of country risk premium information. He periodically publishes country risk premium information for an extensive list of countries. Once the CAPM market risk premium has been estimated for a mature economy, the country risk premium can help determine by extrapolation a market risk premium specific to other mature economies and to each emerging economy.

6.4. Risk Premium Method

The Risk Premium Method is based on the concept that the common equity of an entity is riskier than the debt of that entity, and thus deserves to earn a premium over the debt yield. The risk premium model can be expressed:

$$k_e = k_d + (R_e - R_d)$$

where K_e = the cost of equity;

k_d = the yield on utility debt;

R_e = the return expected on utility equity; and

R_d = the return expected on utility debt; and

$R_e - R_d$ = the risk premium of utility equity over utility debt.

The risk premium method has some similarities to the CAPM method, although the base yield is a utility debt yield rather than a government debt yield. In order to implement the risk-premium model, it is necessary to estimate the utility debt yield and the appropriate risk premium.

The utility debt yield may be directly observed from the yields on the utility's traded debt securities or ascertained from a credit rating agency bond yield quote for utilities that have a similar credit rating to the subject utility.

The risk premium of equity over debt can be estimated by reviewing the historical relationship of common stock returns to debt returns over time, through a survey approach, or by calculating implied risk premiums from past regulatory ROE decisions.

6.5. Comparable Earnings Method

The Comparable Earnings Method is the oldest of ROE methods, is simple and straightforward, but has generally fallen out of use in the United States. The comparable earnings method is expressed as:

$$ROE = EPS_0/BVPS_0$$

where ROE = the return on equity;

EPS_0 = earnings per share during time period 0, or the most recent period; and

$BVPS_0$ = the current book value of common equity per share.

The Comparable Earnings method requires two inputs: recently reported earnings per share from the income statement and recently reported book value of common equity per share from the balance sheet.

Since it relies only on historical accounting data from financial statements, this approach does not technically measure the cost of equity because no market information is utilized.

The Comparable Earnings method is not market-based or forward-looking and is often criticized for circularity when regulated utilities are utilized in the proxy group. However, the circularity criticism is alleviated if the method is applied to a non-utility proxy group. In emerging economies where market price data is unavailable, an approach based on historical accounting data may be a relatively more attractive method, even if no longer used in mature economies.

6.6. Expected Earnings Method

The Expected Earnings Method shares some similarities to the Comparable Earnings method, but its primary distinguishing characteristic is that it is forward-looking. The Expected Earnings method is expressed as:

$$ROE = EPS_1/BVPS_0 \quad \text{or} \quad ROE = EPS_n/BVPS_{n-1}$$

where ROE = the return on equity;

EPS_1 = earnings per share during time period 1 or the next period after the current period;

EPS_n = earnings per share during time period n;

$BVPS_0$ = the current book value of common equity per share; and

$BVPS_{n-1}$ = the projected book value of common equity per share during time period n-1.

The Expected Earnings methodology provides an accounting-based approach that uses investment analyst estimates of return (net earnings) on book value (the equity portion of a company's overall capital, excluding long-term debt). Thus, the two data components needed to implement the Expected Earnings methodology are: 1) a measure of expected earnings (or earnings per share ("EPS")); and 2) book value of equity (or book value per share ("BVPS")).

Investors place significant weight on expected EPS when making investment decisions. Many sell-side analysts estimate expected EPS out one, two, or three years and at least one investment advisory service publishes expected EPS and expected BVPS estimates out three-to-five years.

Due to its forward-looking nature, the Expected Earnings method does not suffer from circularity concerns. If adequate EPS projections are available for the subject utility and/or proxy group but market price data are not, the Expected Earnings Method may be a relatively more attractive method to utilize in emerging economies.

6.7. Other Cost of Equity Methods

The aforementioned five cost of equity methods are highlighted separately because, to some degree, they have achieved common usage over time by investors and regulatory commissions. Investors value models with conceptual appeal and practical usefulness. Academics and investors are on a continual quest to discover and explore new financial models.

Some other potential cost of equity models, such as the Arbitrage Pricing Theory model and the complex multi-factor Fama-French model, are promising methods that have some conceptual appeal but are still impractical. Arbitrage Pricing Theory is a multi-factor asset pricing model that attempts to predict an asset's return using a linear relationship between the asset's expected return and a number of macroeconomic variables that attempt to measure systematic risk. The Fama-French model is an asset pricing model based on an econometric regression of historical stock prices that attempts to expand on the CAPM market risk factor by adjusting for other factors such as size risk and value risk.

Models that currently have implementational challenges may bear fruit in the future. Regulators should not preclude evidence on these other models in the future as their implementational challenges may be solved. A detailed explanation of these methods is beyond the scope of this primer.

6.8. Issuance Costs

Issuance costs, also called flotation costs, are sometimes identified as an increment that must be added to the base cost of equity for ratemaking purposes. When a company raises common equity capital, it experiences costs of issuance including an underwriting fee as well as legal, accounting, printing, and other out-of-pocket costs. Issuance costs are generally deducted from the market price at the time of issuance to quantify the net proceeds available and thus represent permanently foregone capital. These necessary costs of doing business can be reflected in the revenue requirement as a one-time expense or through an ROE increment that usually is measured in basis points.

6.9. Incentive Adders

In certain circumstances, a regulator may desire to or may even be mandated to provide an incentive for a utility to invest in specific infrastructure. The desire may stem from an identified regulatory policy need or legislation that mandates that the construction of specific infrastructure should be encouraged. After determining the base ROE equal to the cost of equity, an incentive adder can be added above and beyond the base ROE, resulting in an incentive ROE that is higher than the base ROE. For example, the United States Congress passed the Energy Policy Act of 2005 that encouraged the Federal Energy Regulatory Commission ("FERC") to provide incentives for electric transmission to be constructed.[5] The FERC responded by crafting several incentive adders that were subsequently added to the base ROE of electric transmission providers resulting in successful electric transmission investment.[6]

6.10 Regulatory ROE Discretion When Evaluating Cost of Equity Evidence

When making ROE decisions, it is typical for regulatory commissions to be confronted with the perpetual challenge of having a record consisting of multiple ROE methodologies from multiple ROE witnesses representing multiple parties. Amid the plethora of evidence before it, the regulatory commission is charged with considering and weighing all the evidence and determining a specific authorized ROE for use in developing tariffs. The "weighing" part is challenging and can be different in each commissioner's

[5] The Energy Policy Act added new Section 219 to the Federal Power Act.

[6] FERC implemented Section 219 through Order No. 679 in July 2006 and clarified its implementation with a 2012 Policy Statement.

reasoning, but the task at hand for commissioners is to agree to an authorized ROE that is within the range or zone defined by the evidence.

There are circumstances that may lead a commission to conclude that a measure of central tendency such as the midpoint or the mean of the ROE range is appropriate, but at other times, the weight of the evidence dictates that there is reason to select a different point in the range. It is not surprising that under case-specific circumstances, commissions may choose to emphasize a particular methodology while downplaying that same methodology in different circumstances. Similarly, it is not surprising that under certain circumstances, a commission may find that it is appropriate to give more weight to the upper or lower part or even the very top or very bottom of the range.

An ROE recommendation by a witness or an ROE decision by a regulator requires both the application of financial models and the use of informed judgment. An ROE based solely on judgment would be inappropriate, as would be an ROE that relied solely on the mechanistic and arbitrary application of financial models. In my opinion, it is common for regulatory commissions to acknowledge that any financial model, no matter how conceptually appealing and well-supported, needs to be supplemented with informed judgment. Commissions are on a constant quest to balance the theoretical with the practical.

One recent circumstance that may make a regulator cautious about the results of ROE models is the global financial crisis of 2008. In response to the global financial crisis, the Federal Reserve Bank in the United States, the European Central Bank, the Bank of Japan, and other global central banks began a massive monetary stimulus intervention in late 2008 / early 2009 with the goal of manipulating interest rates lower. Besides very low interest rates, a significant component of the monetary stimulus was quantitative easing, or the ramp up and maintenance of an unprecedented level of debt securities held on the balance sheets of central banks.

Some key parts of the world, including Japan and significant portions of Europe, are experiencing negative interest rates as a result of central bank intervention. Negative interest rates are unsustainable and indicate that investors are paying for the privilege of holding government debt. On October 1, 2019, a Wall Street Journal article stated that "$15 trillion in government debt globally now has negative yields, meaning investors are paying for the privilege of parking their money with a sovereign issuer."[7] The capital marketplace is globally competitive and negative interest rates in some countries have a dampening spillover impact on interest rates even in countries where interest rates still remain positive although extraordinarily low.

Model risk can be magnified especially when global interest rates are negative. As a result, regulators may wish to be even more cautious with ROE modeling results when qualitatively considering ROE evidence produced by market-based financial models during a time period of negative global interest rates.

7. Combining Capital Markets Concepts – Estimating a Utility's WACC

The WACC, as described in Section 3, is determined by combining the capital structure components and cost rate estimates as described in Section 4, 5, and 6. Re-stating the WACC equation from Section 3 in an expanded fashion:

[7] Ira Iosebashvili, "Investors Search For Yield as Outlook Darkens on Growth," The Wall Street Journal, October 1, 2019.

$$WACC = LTD/C \times K_{ltd} + STD/C \times K_{std} + PS/C \times K_{ps} + CE/C \times K_e$$

where WACC = Weighted Average Cost of Capital;

LTD = Total long-term debt;

STD = Total short-term debt;

PS = Total preferred stock;

CE = Total common equity;

C = Total capital = total debt plus total equity;

K_{ltd} = the cost of long-term debt;

K_{std} = the cost of short-term debt;

K_{ps} = the cost of preferred stock; and

K_e = the cost of common equity.

Regulators can accomplish the goal of a cost-reflective tariff by setting the authorized ROE for a utility equal to the cost of common equity and setting the authorized ROR equal to the WACC.

For comparison purposes, recent regulatory decisions regarding approved ROEs and RORs across the globe are shown in Appendices B, C, and D. Appendix B shows comprehensive average ROE and ROR data for U.S. electric and natural gas utilities in approximately 53 jurisdictions since 2004 through 2019. Appendix C shows ROE and ROR data for Ontario regulated utilities from 2010 to 2020. The ROE and ROR are generally approved during the fourth quarter of the prior year and applied to all subsequent Ontario rate filings. Appendix D provides observations about authorized ROEs and RORs in other global jurisdictions.

8. Final Remarks

Cost-based regulation and tariff-setting is key to ensuring that safe, reliable, and affordable utility service is provided to customers. WACC estimates are integral to cost-based regulation. This primer describes capital markets concepts and financial models that are useful in estimating the WACC. Utilizing these capital markets concepts and financial models in combination with informed judgment is beneficial to utilities, investors, and customers.

Appendix A

Proxy Group Selection Process Example from FERC Opinion No. 531 (Docket No. EL11-66-001)
Using Data from the Six-Month Period Beginning October 2012 and Ending March 2013

Company Name	Cost of Equity Result
ALLETE, Inc.	9.95%
Alliant Energy Corp.	9.63%
American Electric Power Co., Inc.	8.17%
Avista Corp.	9.07%
Black Hills Corp.	9.57%
CenterPoint Energy, Inc.	8.89%
Cleco Corp.	10.10%
CMS Energy Corp.	9.60%
Consolidated Edison, Inc.	7.12%
Dominion Resources, Inc.	10.67%
DTE Energy Co.	8.46%
Duke Energy Corp.	8.98%
El Paso Electric Co.	7.03%
Empire District Electric Co.	8.28%
FirstEnergy Corp.	9.91%
Great Plains Energy Inc.	9.99%
Hawaiian Electric Industries, Inc.	8.50%
IDACORP, Inc.	7.59%
Integrys Energy Group, Inc.	10.39%
NextEra Energy, Inc.	9.42%
Northeast Utilities	10.62%
NorthWestern Corp.	9.08%
OGE Energy Corp.	7.43%
Otter Tail Corp.	9.51%
Pepco Holdings, Inc.	9.45%
PG&E Corp.	7.94%
Pinnacle West Capital Corp.	10.56%
Portland General Electric Co.	9.14%
PPL Corp.	8.31%
SCANA Corp.	8.77%
Sempra Energy	8.82%
Southern Company	9.16%
TECO Energy, Inc.	8.58%
UIL Holdings Corp.	11.74%
Vectren Corp.	9.55%
Westar Energy Corp.	10.34%
Wisconsin Energy Group	8.64%
Xcel Energy, Inc.	8.87%
Zone of Reasonableness	7.03% to 11.74%
Midpoint	9.39%
75^{th} Percentile	10.57%

Appendix B

United States Authorized ROE and ROR Data

Annual Averages of Up to 53 Jurisdictions - 2004 through 2019

Year	Electric Utility ROE	Gas Utility ROE	Electric Utility ROR	Gas Utility ROR
2004	10.81%	10.63%	8.71%	8.51%
2005	10.51	10.41	8.44	8.24
2006	10.32	10.40	8.32	8.44
2007	10.30	10.22	8.18	8.11
2008	10.41	10.39	8.21	8.49
2009	10.52	10.22	8.24	8.15
2010	10.37	10.15	8.01	7.99
2011	10.29	9.92	8.00	8.09
2012	10.17	9.94	7.95	7.98
2013	10.03	9.68	7.66	7.43
2014	9.91	9.78	7.60	7.65
2015	9.85	9.60	7.38	7.34
2016	9.77	9.54	7.28	7.08
2017	9.74	9.72	7.18	7.26
2018	9.60	9.59	6.90	7.00
2019	9.65	9.71	6.97	7.17

Source: S&P Global Market Intelligence RRA Regulatory Focus Major Rate Case Decisions.

Appendix C

Province of Ontario (Canada) Authorized ROE and ROR Data from Ontario Energy Board
Dates Shown are Rate Effective Dates

Date	ROE	ROR
May 1, 2010	9.85%	7.31%
Jan 1, 2011	9.66%	7.03%
May 1, 2011	9.58%	6.91%
Jan 1, 2012	9.42%	6.66%
May 1, 2012	9.12%	6.20%
Jan 1, 2013	8.93%	5.91%
May 1, 2013	8.98%	5.98%
Jan 1, 2014	9.36%	6.56%
Jan 1, 2015	9.30%	6.48%
Jan 1, 2016	9.19%	6.28%
Jan 1, 2017	8.78%	5.67%
Jan 1, 2018	9.00%	6.02%
Jan 1, 2019	8.98%	6.02%
Jan 1, 2020	8.52%	5.32%

Appendix D

Observations of Other Global Authorized ROEs and RORs

ALBERTA - In 2018, the Alberta Utilities Commission approved a generic three-year ROE of 8.50% for ten electric and natural gas utilities in the Canadian province of Alberta for 2018, 2019, and 2020. Specific RORs were not identified.

AUSTRALIA - In December 2018, the Australian Energy Regulator approved an ROE of 6.36% and ROR of 5.36%, down from a previous ROE of 7.25% and ROR of 5.76%. The ROR but not the ROE is expected to be updated annually while both are binding on subsequent electric and natural gas regulatory determinations.

BRAZIL - In March 2020, the Brazil Electricity Regulatory Agency approved an ROE of 13.99% and ROR of 11.10% for electric distribution utilities, in comparison to a previous ROE of 13.57% and ROR of 12.26%. Also in March 2020, the Brazil Electricity Regulatory Agency approved an ROE of 12.97% and ROR of 10.57% for electric transmission and generation companies, in comparison to a previous ROE of 13.88% and ROR of 11.20%.

PHILIPPINES – In November 2010, the Philippines Energy Regulatory Commission approved an ROE of 20.67% and ROR of 15.04%. In June 2011, the Philippines Energy Regulatory Commission approved an ROE of 16.12%% and ROR of 14.97%. In August 2012, the Philippines Energy Regulatory Commission approved an ROE of 16.44%% and ROR of 13.59%. In March 2014, the Philippines Energy Regulatory Commission approved an ROE of 14.71%% and ROR of 12.41%. In June 2018, the Philippines Energy Regulatory Commission approved an ROE of 13.71%% and ROR of 10.98%. In June 2018, the Philippines Energy Regulatory Commission approved an ROE of 12.23%% and ROR of 10.37%. In September 2019, the Philippines Energy Regulatory Commission approved an ROE of 13.67%% and ROR of 10.74%.

SINGAPORE – In November 2018, the Singapore Energy Market Authority approved an ROE of 9.39% and a post-tax ROR of 7.13% for final determinations in 2019 to 2020, up from an ROE of 8.66% and a post-tax ROR of 6.65% that applied during 2017 to 2018. A post-tax ROR reflect the cost of debt on a post-tax basis and thus appears lower than a pre-tax ROR.

Some global authorized ROEs and RORs, such as those in the United Kingdom and South Africa, are quoted on a real (inflation-adjusted) basis rather than a nominal basis, thus making cross-country comparisons challenging. Real returns are lower than nominal returns.

ANNEX 1: A COST OF CAPITAL AND CAPITAL MARKETS PRIMER FOR UTILITY REGULATORS – A CASE STUDY

Project Title:	A Cost of Capital and Capital Markets Primer for Utility Regulators Annex 1: Case Study
Sponsoring USAID Office:	Energy Division, Office of Energy & Infrastructure, Bureau for Economic Growth, Education, and Environment (E3)
Cooperative Agreement #:	AID-OAA-A-16-00042
Recipient:	National Association of Regulatory Utility Commissioners
Date of Publication:	March 2020
Author:	John D. Quackenbush, CFA, President, JQ Resources, LLC

National Association of Regulatory Utility Commissioners

This publication is made possible by the generous support of the American people through the United States Agency for International Development (USAID). The contents are the responsibility of the National Association of Regulatory Utility Commissioners (NARUC) and do not necessarily reflect the views of USAID or the United States Government.

Annex 1 Case Study Table of Contents

1. Introduction

With the support of the United States Agency for International Development (USAID) – Energy Division, Office of Energy & Infrastructure, the National Association of Regulatory Utility Commissioners (NARUC) has undertaken the task of developing a Cost Reflective Tariff Toolkit which contains a chapter on Cost of Capital and Capital Markets for Utility Regulators. This toolkit is intended to constitute several short practical primers that can be used by utility regulators in countries with emerging economies to design rates that are based on actual cost of service and to effectively engage the public and key stakeholders in the decision-making process. This Annex 1 case study is appended to and is to be read in the context of the toolkit chapter on Cost of Capital and Capital Markets.

1.1 Objective and Process

The objective of this Annex 1 case study is to help utility regulators in countries with emerging economies understand how cost of capital is used in the utility tariff-setting process through an example country, the Philippines. The cost of capital is one of the key components of effective cost-based ratemaking and developing cost-reflective tariffs. This Annex 1 case study describes how the Philippines Energy Regulatory Commission (ERC) estimates the cost of capital for its regulated entities.

In terms of the process to develop this case study, the author researched regulatory orders and other documents of the Philippines ERC. The author conducted meetings with Philippines ERC staff representatives, Commissioner Josefina Patricia A. Magpale-Asirit, and representatives from three regulated entities.

1.2 Scope and Overview

This annex focuses on describing a set of pathways that regulators in countries with emerging economies may want to consider when estimating the cost of capital for use in determining the utility revenue requirement in ratemaking. This set of pathways is based on the Philippines utility regulator's practices in estimating the cost of capital. Furthermore, the pathways include some observations to facilitate the incorporation of regional differences between the U.S. and countries with emerging economies.

The Philippines is an archipelagic country consisting of more than 7,600 islands with a population of 108.9 million and averages 20 tropical cyclones per year. The Philippines economy is growing at a healthy annual rate of 6.2% and is divided into agriculture (8.1%), industry (34.1%), and services (57.8%). The most important economic sectors include electronics assembly, business process outsourcing, food manufacturing, shipbuilding, chemicals, textiles, garments, metals, petroleum refining, fishing, and rice. The currency is the Philippine peso.

The Philippines power system is divided into three grids: Luzon (North), Visayas (Central), and Mindanao (South), following natural geographical divisions. There is an interconnection between the Luzon and Visayas grids, while it is expected that the Visayas and Mindanao grids will be interconnected by 2023. One transmission owner, the National Grid Corporation of the Philippines (NGCP), provides all transmission services. Given the large number of islands, there are a large number of off-grid missionary areas with isolated grids.

Electricity distribution occurs through 20 investor-owned utilities and 121 electric cooperatives, serving an aggregate load of 90,758 GWh. The distribution and transmission utilities do not own generation. In aggregate, the electric load is 31% residential, 27% commercial, 30% industrial, and 12% other. The typical residential customer electric bill consists of 31% distribution, 12% transmission, 41% generation, and 16% government taxes and subsidies.

All electric generation is provided by third parties except for some legacy generation owned by the government (approximately 10%) which is intended to be divested to third parties over time. The third-party power producers sign power service agreements (PSAs) with the distribution utilities, essentially bilateral contracts. There are more than 200 generation facilities with installed capacity of 23.82 GW providing 99,765 GWh of gross generation. The aggregate fuel mix is approximately 37% coal, 14% natural gas, 30% renewables, and 18% oil-based. The 30% renewable energy slice consists of 15% hydro, 8% geothermal, 4% solar, 2% wind, and 1% biomass.

The current electricity market was shaped by two key pieces of legislation: the Electric Power Industry Reform Act (EPIRA) of 2001 and the Renewable Energy (RE) Act of 2008. EPIRA restructured the electric power industry by privatizing government-owned generation assets (a task that has mostly been completed but some vestiges are still pending) and defining the competitive framework, while creating and defining the roles of various governmental agencies including the Energy Regulatory Commission (ERC).

The ERC is an independent, quasi-judicial regulatory body that promotes competition, ensures customer choice, sets rates, and imposes fines and penalties. There are five commissioners appointed by the President that serve seven-year terms, with one commissioner designated as the Chair. The ERC staff is divided into the following six divisions: Regulatory Operations Service, Market Operations Service, Consumer Affairs Service, Financial and Administrative Service, Legal Service, and Planning and Public Information Service, reporting up through an Executive Director. Approximately 30 staff members with engineering, accounting, and economics backgrounds are involved in some aspect of rate-setting.

The RE Act accelerated the development of renewable energy resources by providing incentives to private sector investors and equipment manufacturers and suppliers, and continues to shape the electric generation fuel mix.

1.3 Organization

The organization of this Annex 1 case study is patterned after the primer organization as follows:

Section 2 provides a Philippines capital markets overview.

Section 3 provides an ERC cost of capital overview.

Section 4 describes the ERC capital structure components.

Section 5 describes the ERC cost rate of debt.

Section 6 explains the ERC cost of common equity.

Section 7 summarizes how the preceding concepts are combined by the ERC to estimate a utility's weighted average cost of capital.

Section 8 concludes with final remarks.

2. Capital Markets Overview

The debt and equity capital markets in the Philippines are relatively small and illiquid and thus somewhat limited in providing the data needed in order to directly measure the cost of capital for Philippines utilities. Some cost of debt data is directly available for Philippines government debt. As will be mentioned in Section 4 on the Cost of Equity, global proxy groups are important in order to indirectly measure the cost of equity.

The Philippines central bank, Bangko Sentral ng Pilipinas, conducts monetary policy that is considered accommodative and is considering further monetary policy easing in 2020. The policy interest rate is set between 3.5% and 4.0% and is considered likely to remain in that range through 2023.

The Philippines government has outstanding Treasury debt securities that can be used in measuring the cost of debt, but there is a concern that the Philippines bond market is not stable or consistent.

Minimal credit rating information is available on fixed income securities. The Philippines government has bonds that have investment grade credit ratings from S&P of "BBB+", Moody's of "Baa2", and Fitch of "BBB". S&P raised the Philippines sovereign rating from "BB+" to "BBB-" on May 2, 2013, to "BBB" on May 8, 2014, and to "BBB+" on April 30, 2019. Moody's upgraded the Philippines from "Ba1" to "Baa3" on October 3, 2013 and to "Baa2" on December 11, 2014, while Fitch moved from "BB+" to "BBB-" on March 27, 2013 and to "BBB" on December 10, 2017. The credit rating agencies commented that the transition from speculative grade to and through investment grade was enabled by strong and consistent macroeconomic performance underpinned by sound policies that are supporting high and sustainable growth rates, ongoing fiscal restraint, debt reduction, political stability, improved governance, enhanced budget transparency, an improved monetary policy environment, and expectations of continued improvement in credit metrics.

The only entity regulated by the Philippines ERC that has its own credit rating is Meralco, the largest distribution utility, which is rated "BBB-" by S&P, the lowest investment grade rating. S&P is the only credit rating agency that rates Meralco. S&P upgraded Meralco from the speculative grade of "BB+" to the investment grade of "BBB-" on June 21, 2017, citing financial discipline, moderate leverage, stable margins, moderate growth, and better clarity on Meralco's five-year capital spending plan.

Bank loans of various terms are available primarily from Asian investors. Tenors vary from 8 years to 15 years. The generation providers generally issue bank loan debt related to specific generating projects and make periodic payments that are part interest expense and part repayment of principal.

In terms of equity markets, there are approximately 260 traded companies listed on the Philippines Stock Exchange. Eleven entities are included in the broad Electricity, Energy, Power, and Water sector. Four entities are in the energy business and one is in the water utility business. The only electricity distribution utility is Meralco. The other five listed entities are power generation companies that tend to be diversified into other business as well. There are no traded transmission companies. There is minimal sell-side investment community analysis and virtually no published investment research available. As a result, it is difficult to avoid looking to global proxy companies when estimating the cost of equity, as described in Section 6.

This indirect measurement of capital costs is not a problem because capital markets are global, with Philippines utility investments competing against alternatives across the world on a risk-adjusted basis. Capital funds should readily flow to Philippines utilities that provide attractive risk-adjusted returns.

3. Cost of Capital Overview

As part of its economic regulation and rate-setting duties, the Philippines ERC has three primary usages of WACC: distribution, transmission, and generation. WACC is generally built into the revenue requirement, rates, and tariffs of all three primary components of a customer's electric bill.

For distribution, the 20 investor-owned utilities are subject to performance-based regulation based on WACC. For rate-setting, the 20 distribution utilities are divided into four groups that are intended to be reviewed every four years on a staggered rotating basis. Meralco is the largest investor-owned distribution utility, serving roughly 70% of all customer load. The most recent distribution WACC review for Group 1 distribution utilities including Meralco was completed in June 2011 for the regulatory tariff period of July 2011 – June 2015. The ERC does not rely on WACC for rate-setting for the 120 electric cooperatives.

The ERC sets transmission rates through performance-based regulation based on WACC. NGCP is the only electric transmission provider and the intent is to review its WACC every five years. The most recent transmission WACC review was completed in November 2010 for the regulatory tariff period of 2011 – 2015.

As evident by the foregoing dates, the ERC has not completed subsequent distribution/transmission WACC determinations on the original schedule. Some non-WACC policy issues and court cases derailed a series of orders that the ERC was scheduled to issue in 2016-2017. The prior rates continue to apply.

For power generation, the ERC reviews and approves the WACC built into the capital recovery fee component of rates determined in individual Power Service Agreements (PSAs). A PSA is a bilateral contract for a distribution utility to buy power from a specific generating station of an independent power producer for a specific time period and are generally for newly constructed generating stations. Once negotiated, the PSA is jointly submitted to the ERC by the independent power producer and the distribution utility. The proposed PSA rates are designed to recover a negotiated pretax WACC. The ERC has the authority to review the WACC in a proposed PSA and potentially alter it. The ERC-approved WACC is then built into the upfront PSA approval and intended to remain unchanged for that generating station for the life of the PSA. This annex summarizes five PSA decisions that were issued between August 2012 and September 2019. The ERC does not use WACC for the 10% vestige of government-owned generation that has not yet been divested to third parties.

The typical WACC regulatory process starts with the distribution/transmission utility or joint generation applicants proposing a WACC. It is rare for Philippines intervenors to offer testimony supporting a different WACC. The ERC staff also does not submit WACC testimony, but the technical staff reviews the evidence, prepares a memorandum with a WACC recommendation, and presents it to the Commissioners for their deliberations. The legal staff conducts the hearings and prepares a draft order.

The ERC WACC approach for distribution, transmission, and generation is based on an analysis of the capital structure and the cost rates of the individual capital components as follows:

$$WACC = D/C \times K_d + E/C \times K_e$$

where WACC = Weighted Average Cost of Capital;

D = Total debt;

E = Total equity;

C = Total capital = total debt plus total equity;

K_d = the cost of debt; and

K_e = the cost of equity.

The debt, equity, and capitalization variables of the WACC equation are explained in Section 4. The cost of debt variable of the WACC equation is described in Section 5 while the cost of equity variable is derived as explained in Sections 6.

4. Capital Structure Components

The ERC generally focuses on two investor-supplied capital structure components: debt and equity. It appears that no regulated entities have outstanding preferred stock. Short-term debt is not explicitly considered as a separate capital component.

In capital structure determination, the ERC staff explained that the ERC's goal is to set an "efficient" capital structure. As such, the ERC does not explicitly focus on book value capital structures or market value capital structures. Nor does it explicitly focus on a utility's actual capital structure, its parent capital structure, or a hypothetical capital structure.

In the most recent Group I distribution order, the ERC used a capital structure of 40% debt and 60% equity as the base case, but sensitized the analysis for 45% debt and 55% equity and 35% debt and 65% equity. Ultimately, the ERC decided to base the WACC on the 75th percentile of that range, so the order approximated using a capital structure of 37.5% debt and 62.5% equity.

For transmission, the ERC most recently focused on NGCP's average capital structure planned during the regulatory period. The result was a capital structure of 67% debt and 33% equity.

In five recent PSA cases, a newly constructed generation project was being project-financed with bank loans and equity. In these cases, the ERC used an actual capital structure that reflects the project financing for the specific generating station. In three of the recent cases, the ERC used a 70% debt and 30% equity capital structure for power generation. The two other cases used capital structures of 59.3% debt and 40.7% equity and 63.4% debt and 36.6% equity.

As a result of using these capital structure approaches, extensive balance sheet analysis of book value was not needed. Also, parent company balance sheet analysis was not needed.

5. Cost Rate of Debt

In all cases, the ERC focuses on the incremental cost of long-term debt, rather than the embedded cost of debt. It appears that no regulated entities have outstanding preferred stock, so there is no need to determine the cost of preferred stock. Short-term debt is not explicitly considered as a separate capital component, so there is no need to determine the cost of short-term debt.

In general, the recent ERC orders prepared the cost of debt calculation on either an indirect method based on United States Treasury yields or a direct method based on Philippines Treasury yields. The United States debt market is more liquid, while the Philippines market is more reflective of local circumstances. The ERC staff prefers to use the local direct method if adequate information is available.

Over time, the ERC has used either the direct or indirect method and sometimes calculates both and then chooses between them. The indirect cost of debt method adds a Philippines country risk premium, a differential between the Philippines inflation rate and the United States inflation rate, and a utility debt margin to the United States Treasury yield. The country risk premium is generally sourced from Damodaran or from the ERC's own comparison of Philippines and United States Treasury yields. The direct cost of debt method adds a utility debt margin to the Philippines Treasury yield.

Also, in some cases, when a desired tenor does not match up with an actual or a quoted index interest rate, the ERC interpolates between available tenors to approximate the cost rate for the desired tenor.

In the most recent Group 1 distribution order involving Meralco, the ERC explained that it had in the past focused on a ten-year tenor when determining the cost of debt. However, the ERC used this order to shift to a 20-year tenor based on its concern about extremely low yields on both United States and Philippines short-dated securities. The ERC recognized that the extremely low yields were linked to global central banks' manipulation of interest rates including enormous quantitative easing in the United States. In estimating the incremental cost of 20-year debt, the ERC began with a base case United States Treasury yield of 4.32% and then added a country risk premium of 1.46%, an adjustment for the differential in inflation rates of 4.02%, and a utility debt margin of 2.50%, resulting in a base case cost of debt of 12.30%. The ERC then sensitized the analysis for cost of debt to a range of 10.80% to 13.79%. Ultimately, the ERC decided to base the WACC on the 75th percentile of that range, so the order approximated using a cost of debt of 13.05%.

For transmission, the ERC most recently determined the cost of debt for NGCP to be 12.27%. This cost of debt was based on a United States 20-year tenor Treasury yield of 3.91%, a country risk premium of 2.32%, an adjustment for the differential in inflation rates of 3.54% and a utility debt margin of 2.50%.

In multiple recent PSA cases, when a newly constructed generation project was being project-financed in part with bank loans, the ERC used the actual cost of debt reflective of the bank loans supporting the specific generating station. Examples include a 9.34% rate based on an 8.5-year tenor, a 7.44% rate based on a 12.5-year tenor, a 7.00% rate based on a 15-year tenor, a 5.50% rate based on two loans with tenors of 8 and 15 years, and a 6.98% rate based on a 15-year tenor. The bank loans are generally tied to the Philippines dealing system Treasury fixing (PDST-F) rate, United States Treasury yields, or LIBOR.

As a result of using an incremental rather than embedded cost of debt approach, an analysis of vintages of debt on the balance sheet is not needed.

6. Cost of Common Equity

The ERC's primary method to estimate the cost of equity is the Capital Asset Pricing Model (CAPM). One of the key components of the CAPM is the beta, which is a market-based risk measure. The Philippines utilities are generally not market-traded. When the subject entity is not market-traded, the frequent solution is to select a proxy group of market-traded companies.

The identification of proxy groups can be especially challenging in developing countries. The general proxy group selection process implemented by the ERC is to use Bloomberg as a source of proxy group information. The goal is to select proxy companies that are comparable in risk to the subject utility. Once the proxy group is identified, the ERC can review the beta for each company in the proxy group and aggregate the results through averaging. The resulting average beta for the proxy group is then de-levered into an asset beta, then re-levered to adjust for the leverage of the subject utility through a process called a Hamada adjustment. The resulting average cost of equity estimate for the proxy group serves as an estimate for the subject utility's cost of equity.

For Meralco and Group 1 distribution utilities, Bloomberg was used as a source to review potential proxy companies including global electric transmission providers, gas transmission providers, and vertically integrated electric utilities. Based on a screening process for data availability, liquidity, a low percentage of generation and non-utility operations, and other factors, seventeen vertically integrated proxy companies were selected including seven from the United States, two each from Brazil, Chile, and Japan; and one each from Britain, Malaysia, New Zealand, and Russia. The average beta for the seventeen proxy companies was de-levered resulting in an asset beta of 0.499.

For NGCP, Bloomberg was used as a source to review potential proxy companies including global electric transmission providers, gas transmission providers, and vertically integrated electric utilities. Based on a screening process for data availability, liquidity, a low percentage of generation and non-utility operations, and other factors, seven proxy companies were selected including four electric transmission providers from Argentina, Brazil, Columbia, and Spain, and three vertically integrated electric utilities from Malaysia, Pakistan, and the United States. The average beta for the seven proxy companies was de-levered resulting in an asset beta of 0.553.

The power generation PSA cases appear to use a conceptually similar proxy group selection approach. In the earlier PSA decisions, the ERC used a group of comparable risk power generation companies sourced from Professor Damodaran. The details of the Damodaran approach are not specified in the orders. This analysis resulted in power generation betas close to 1.0, above the utility asset betas and approximating the average market portfolio beta. The betas close to 1.0 also makes the de-levering and re-levering process somewhat insignificant for power generation.

6.1 The Value of Using Multiple Financial Models

Recent WACC decisions of the Philippines ERC have been based on the Capital Asset Pricing Model. The ERC staff indicated an interest in perhaps exploring other methods, particularly the Discounted Cash Flow Model, in future cases.

6.2. Discounted Cash Flow Model

The Discounted Cash Flow (DCF) approach has not been used by the ERC in recent WACC decisions, but the ERC staff indicated an interest in perhaps considering it in future cases.

6.3. Capital Asset Pricing Model

The ERC's primary method to estimate the cost of equity is the Capital Asset Pricing Model (CAPM). The Capital Asset Pricing Model (CAPM) approach is based on the theory that the required rate of return for a given security is equal to the risk-free rate of return plus a risk-adjusted risk premium. Financial theory presents the CAPM relationship as:

$$k_e = R_f + B_j \times (R_m - R_f)$$

where k_e = the cost of equity;

R_f = the risk-free rate of return;

R_m = the expected return on the market portfolio;

B_j = the measure of risk for stock j, or beta; and

$R_m - R_f$ = the market risk premium.

In order to implement the CAPM model, the ERC calculates the risk-free rate, the beta, and the market risk premium, while generally incorporating a country risk premium into the risk-free rate.

In general, the ERC develops the risk-free rate in a conceptually compatible way to the manner in which it develops the cost of debt, either from an indirect method based on United States Treasury yields or a direct method based on Philippines Treasury yields, as described in Section 5 of this Annex. The indirect risk-free rate method adds a Philippines country risk premium and a differential between the Philippines inflation rate and the United States inflation rate to the United States Treasury yield. The country risk premium is generally sourced from Damodaran or from the ERC's own comparison of Philippines and United States Treasury yields. The direct risk-free rate method simply uses the Philippines Treasury yield.

Betas emerge from the proxy group analysis. The asset betas are re-levered through a Hamada adjustment to synch with the leverage in the capital structure of the subject utility.

The ERC generally sources the market risk premium from Professor Damodaran's publications.

Turning to the most recent Group 1 distribution order involving Meralco, the ERC explained that it had in the past focused on a ten-year tenor when determining the risk-free rate. However, the ERC used this order to shift to a 20-year tenor based on its concern about extremely low yields on both United States and Philippines short-dated securities, conceptually consistent with its cost of debt calculation. The ERC recognized that the extremely low yields were linked to global central banks' manipulation of interest rates including enormous quantitative easing in the United States. In estimating the 20-year risk-free rate, the ERC began with a base case United States Treasury yield of 4.32% and then added a country risk premium of 1.46% and an adjustment for the differential in inflation rates of 4.02%, resulting in a base case risk-free rate of 9.80%. The ERC then sensitized the risk-free rate analysis to a range of 8.80% to 10.79%. Ultimately, the ERC decided to base the WACC on the 75th percentile of that range, so the order approximated using a risk-free rate of 10.30%.

The Meralco and Group 1 asset beta of 0.499 that emerged from the proxy group analysis was already de-levered. A Hamada adjustment was applied to re-lever the asset beta, resulting in a beta of 0.83. The ERC then sensitized the beta analysis to a range of 0.50 to 1.11. Ultimately, the ERC decided to base the WACC on the 75th percentile of that range, so the order approximated using a beta of 0.97.

For Meralco and Group 1, the ERC used a base case market risk premium sourced from Damodaran of 6.00% and did not sensitize the market risk premium to a range like it did the other variables.

The base case Meralco and Group 1 cost of equity is 14.78%. The ERC then sensitized the risk-free rate analysis to a range of 11.81% to 17.45%. Ultimately, the ERC decided to base the WACC on the 75th percentile of that range, so the order results in an approximate ROE of 16.12%.

For transmission, the ERC most recently determined the risk-free rate for NGCP to be 9.77%. This risk-free rate was based on a United States 20-year tenor Treasury yield of 3.91%, a country risk premium of 2.32%, and an adjustment for the differential in inflation rates of 3.54%. The ERC used the 20-year tenor for reasons similar to the Meralco order. It deemed the 5-year and 10-year tenors unrepresentative because of the extreme quantitative easing in the United States. The ERC also calculated an alternative risk-free rate of 9.04% through the direct method based on 20-year Philippines Treasury yields, but chose to use the indirect method instead.

The NGCP asset beta of 0.553 that emerged from the proxy group analysis was already de-levered. A Hamada adjustment was applied to re-lever the asset beta, resulting in a beta of 1.82.

For NGCP, the ERC used a market risk premium sourced from Damodaran of 6.00%.

The ERC's CAPM approach resulted in an NGCP ROE of 20.67%.

In multiple recent PSA cases, the ERC determined risk-free rates in a range of 3.63% to 6.40% at different times based mostly on the direct method with reference to Philippines Treasury yields. The ERC used a power generation beta of 1.00 in three cases and 1.03 in two cases. For the market risk premium and the country risk premium, the ERC primarily used Damodaran as a source, resulting in market risk premiums at different times ranging from 5.08% to 6.00% and country risk premium at different times ranging from 2.19% to 4.13%. The resulting power generation ROEs in the five cases were 16.44%, 14.71%, 13.71%, 12.23%, and 13.67%.

6.4. Risk Premium Method

The ERC has not used the Risk Premium Method in recent WACC decisions.

6.5. Comparable Earnings Method

The ERC has not used the Comparable Earnings Method in recent WACC decisions.

6.6. Expected Earnings Method

The ERC has not used the Expected Earnings Method in recent WACC decisions.

6.7. Other Cost of Equity Methods

The ERC has not used cost of equity methods other than the Capital Asset Pricing Model in recent WACC decisions.

6.8. Issuance Costs

The ERC has not explicitly authorized an issuance cost increment in recent WACC decisions, although the ERC staff expressed an interest in perhaps considering them in future cases.

6.9. Incentive Adders

The ERC has not explicitly authorized incentive adders in recent WACC decisions for either policy or legislative reasons. A 2.00% WACC increment to encourage transmission investment was proposed by NGCP in the most recent case, but was not explicitly approved by the ERC.

6.10. Regulatory ROE Discretion When Evaluating Cost of Equity Evidence

The ERC exercised ROE discretion when evaluating cost of equity evidence in both the Meralco and NGCP orders. The ERC was concerned about extremely low yields on both United States and Philippines short-dated securities and recognized that the extremely low yields were linked to global central banks' manipulation of interest rates including enormous quantitative easing in the United States. The ERC responded by upwardly adjusting both the cost of debt and the risk-free rate in the CAPM.

Moreover, the ERC found it appropriate to give more weight to the upper end of the range and decided to base the Meralco WACC on the 75th percentile of the WACC range, rather than at a measure of central tendency such as the base case midpoint, mean, or median. These regulatory responses are fruitful examples of using informed judgment and exercising ROE discretion when evaluating cost of equity evidence.

7. Combining Capital Markets Concepts – Estimating a Utility's WACC

The WACC, as described in Section 3, is determined by combining the capital structure components and cost rate estimates as described in Section 4, 5, and 6. Re-stating and simplifying the WACC equation from Section 7 of the Primer:

$$WACC = D/C \times K_d + E/C \times K_e$$

where WACC = Weighted Average Cost of Capital;

D = Total debt;

E = Total equity;

C = Total capital = total debt plus total equity;

K_d = the cost of debt; and

K_e = the cost of equity.

Combining the ERC-determined capital components and cost rates for Meralco and the Group 1 distribution utilities:

Distribution Base Case WACC = 13.79% = 40% x 12.30% + 60% x 14.78%

Distribution 75th percentile WACC = 14.97% = 37.5% x 13.05% + 62.5% x 16.12%

Combining the ERC-determined capital components and cost rates for the NGCP electric transmission utility:

NGCP WACC = 15.04% = 33% x 20.67% + 67% x 12.27%

Combining the ERC-determined capital components and cost rates for the five power generation PSAs, results in WACCs of 13.59%, 12.41%, 10.78%, 10.37%, and 10.74%.

8. Final Remarks

This Philippines case study demonstrates capital markets concepts, financial models, and informed judgment that are useful in estimating the WACC to the benefit of utilities, investors, and customers. Annex 1 provides some context to utility regulators in countries with emerging economies about how cost of capital can be used in the tariff-setting process.

ANNEX 2: RETURN ON EQUITY (ROE) INCENTIVES

Project Title:	A Cost of Capital and Capital Markets Primer for Utility Regulators Annex 2: Return on Equity (ROE) Incentives
Sponsoring USAID Office:	USAID/Nigeria
Cooperative Agreement #:	AID-OAA-A-16-00042
Recipient:	National Association of Regulatory Utility Commissioners
Date of Publication:	October 2020
Author:	John D. Quackenbush, CFA, President, JQ Resources, LLC

National Association of Regulatory Utility Commissioners

This publication is made possible by the generous support of the American people through the United States Agency for International Development (USAID). The contents are the responsibility of the National Association of Regulatory Utility Commissioners (NARUC) and do not necessarily reflect the views of USAID or the United States Government.

Annex 2 ROE Incentives Table of Contents

1. Introduction

With the support of the United States Agency for International Development (USAID) – Energy Division, Office of Energy & Infrastructure, the National Association of Regulatory Utility Commissioners (NARUC) has undertaken the task of developing a Cost Reflective Tariff Toolkit which contains a primer on Cost of Capital and Capital Markets for Utility Regulators. This toolkit is intended to constitute several short practical primers that can be used by utility regulators in countries with emerging economies to design rates that are based on actual cost of service and to effectively engage the public and key stakeholders in the decision-making process.

ROE incentive adders were discussed in Section 6.9 of *A Cost of Capital and Capital Markets Primer for Utility Regulators*, completed in April 2020. This Annex 2 report on ROE incentives is appended to and is to be read in the context of the toolkit primer on Cost of Capital and Capital Markets.

1.1 Objective and Process

The objective of this Annex 2 on ROE Incentives is to help utility regulators around the world understand how ROE incentives may be utilized in the utility tariff-setting process. ROE incentives, both rewards and penalties, can serve as an effective cost-based ratemaking tool, facilitate the development of cost-reflective tariffs, and provide customer benefits.

To develop this annex, the author researched regulatory orders and other documents of the Federal Energy Regulatory Commission and several state commissions in the United States.

1.2 Scope and Overview

This annex focuses on describing ROE incentives that regulators in countries with emerging economies may want to consider as tools when establishing the rate of return for use in determining the utility revenue requirement in ratemaking. Actual United States ROE incentive examples that include both rewards and penalties are provided from both the federal and state jurisdictions.

1.3 Organization

The organization of this Annex 2 is patterned after the primer organization as follows:

Section 2 provides a general overview of ROE incentives.

Section 3 describes the federal history with electric transmission ROE incentives.

Section 4 describes the recent FERC NPRM that proposes to reform electric transmission ROE incentives.

Section 5 describes the proposed ROE adder in a recent FERC staff white paper on cybersecurity incentives.

Section 6 summarizes several state regulatory decisions that provide ROE incentives, both rewards and penalties.

Section 7 concludes with final remarks.

2. ROE Incentives Overview

As mentioned in Section 6 of the primer, setting the authorized base ROE equal to the cost of equity is integral to conventional cost of service regulation. However, certain policy considerations may lead a regulatory commission to deviate from convention. The term "performance-based regulation" is often used to describe more comprehensive changes to cost of service regulation. ROE incentives provide a simple tool for regulatory commissions that desire to motivate specific investment behavior by utility management within the conventional cost of service regulatory framework.

In certain circumstances, a regulator may desire to or may even be mandated to provide an incentive for a utility to invest in specific infrastructure. This desire may stem from an identified regulatory policy need or legislation that mandates that the construction of specific infrastructure should be encouraged. After determining the base ROE equal to the cost of equity, an incentive adder can be added above and beyond the base ROE, resulting in an incentive ROE that is higher than the base ROE. Likewise, a penalty can be subtracted from the base ROE, resulting in a penalty ROE that is lower than the base ROE.

This annex describes a variety of ways in which United States regulatory commissions have implemented ROE incentives. A common theme among the various examples is that ROE rewards/penalties were utilized to motivate utility management behavior in a certain direction. As demonstrated by the United States examples in this annex, there are many uses of ROE incentives to benefit customers, including encouraging investments in certain types of generation, energy efficiency programs, peak demand reduction programs, reliability, technological innovation, cybersecurity, environmental compliance and upgrades, advancement of decarbonization objectives, efficient management performance, customer service enhancements, improvements in outage frequency and duration, electric transmission, distribution automation, and smart grid modernization.

3. Federal Electric Transmission ROE Incentives

Multiple decades of underinvestment in United States electric transmission infrastructure led to a legislative directive that serves as a prominent example of ROE incentives. The United States Congress passed the Energy Policy Act of 2005 that encouraged the Federal Energy Regulatory Commission ("FERC") to provide incentives for electric transmission to be constructed.[8] Among other initiatives, the Act directed FERC to provide a return on equity that attracts new investment in transmission facilities including related transmission technologies, while also providing incentives to each transmission owner that joins a Regional Transmission Organization (RTO) or Independent System Operator (ISO) based on the associated significant customer benefits. The Act emphasized that FERC shall establish incentive-based rate treatments for electric transmission for the purpose of benefitting customers by ensuring reliability.

In 2006, FERC responded by crafting several ROE incentive adders that were subsequently made available and added to the base ROE of electric transmission providers resulting in successful electric transmission investment.[9] One of the prominent incentives established by FERC was a 50-basis point ROE adder for RTO/ISO participation based on the significant customer benefits achieved through individual transmission providers turning control of the transmission grid over to RTOs/ ISOs.

[8] The Energy Policy Act added new Section 219 to the Federal Power Act.
[9] FERC implemented Section 219 through Order No. 679 in July 2006 and clarified its implementation with a 2012 Policy Statement.

Another prominent ROE adder was a 100-basis point adder for the formation of a stand-alone transmission company that was structurally separated from an incumbent distribution utility. FERC wanted to encourage the stand-alone transmission company business model.

Additionally, FERC also approved a number of project-specific ROE incentives that were intended to facilitate long-term financing for long-lived electric transmission investments to be allowed on a case-by-case basis, as well as non-ROE incentives.

Subsequently, the 50-basis point RTO/ISO participation adder and project-specific adders achieved widespread implementation, but the 100-basis point stand-alone transmission company adder did not. Only a few stand-alone transmission companies were stimulated. Two received the full 100-basis point adder, while a third received a 50-basis point adder. In 2018, FERC gave up on widespread adoption of the stand-alone transmission business model and reduced the adder for the existing stand-alone transmission companies to 25 basis points.

4. FERC NPRM on Electric Transmission Incentives

In March 2020, FERC issued a Notice of Proposed Rulemaking (NPRM) to reform its electric transmission incentives policies, noting that the landscape for planning, developing, operating, and maintaining transmission infrastructure had change considerably.[10] These observed changes include an evolution in the resource mix, an increase in the number of new resources seeking transmission service, shifts in load patterns, and new challenges to maintaining the reliability of transmission infrastructure.

As a result of the changed landscape, FERC proposes to shift its previous focus on risks and challenges to benefits, thus implementing a benefits test that factors in to the proposed economic benefit-cost test described below.

First considering existing ROE incentives, FERC proposes to revise the RTO/ISO participation adder upwards from 50 to 100 basis points. The RTO/ISO adder would apply across-the-board to all transmission investments rather than to specific projects. One nuance of the proposed RTO/ISO 100-basis point adder the FERC clarified is that it applies regardless of whether RTO/ISO participation is voluntary and even if the transmission provider operates in a state that requires RTO/ISO participation.

FERC also proposes to eliminate the stand-alone transmission company adder that had previously been reduced to 25 basis points. FERC found that this ROE adder did not lead to the expected robust level of transmission investment despite existing for 14 years.

The NPRM proposes to institute several new adders: two 50-basis point adders based on an economic benefit-cost test, a 50-basis point adder for reliability benefits, and a 100-basis point technology adder.

The NPRM provides for two economic benefit-costs test incentives and clarifies that the two economic benefit-cost test incentives are calculated differently, one “ex ante” and one “ex post.” The benefit-cost tests rank order transmission projects based on their benefit to cost ratios. Projects in the top 25% measured “ex ante” pre-construction are entitled to a 50-basis point adder, while projects in the top 10% measured “ex post” at the end of construction are entitled to an additional 50-basis point adder. The "ex

[10] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act Notice of Proposed Rulemaking*, 170 FERC ¶ 61,204 (March 20, 2020), Docket No. RM20-10-000.

post" benefit-cost test would be calculated by updating projected costs to actual construction costs, but not updating the benefit projection.

The benefit-cost tests will heavily rely on existing RTO/ISO benefit-cost analysis, but it may be challenging to systematically synchronize the calculations to ensure comparability across the six United States RTOs/ISOs and other non-RTO/ISO transmission providers. Clearly, these incentives are intended to apply to specific projects and not all projects will qualify. RTO/ISO benefit analyses would carry a rebuttable presumption of accuracy, while benefit analysis provided by a transmission provider either not in an RTO/ISO or substituting its own benefit analysis while in an RTO/ISO would require more scrutiny.

The 50-basis point adder for reliability benefits would apply to specific projects that produce significant and demonstrable reliability benefits above and beyond the requirements of the North American Reliability Corporation (NERC) reliability standards, not across the board. FERC offers five examples of what attributes might qualify projects for the reliability benefit incentive, but requests will be evaluated on a case-by-case basis.

The 100-basis point technology adder would apply to the portion of the project's capital expenditures that is demonstrated to be an advanced technology that enhances reliability, efficiency, and capacity, not to the whole project. Power lines, power poles, capacitors, and most substation equipment are excluded. Examples of technology types that may qualify include advanced line rating management, transmission topology optimization, and power flow control.

Along with this significant number of potential ROE adders, FERC indicated that it must also ensure that rates remain just and reasonable. As a result, FERC is concerned about the cumulative impact, so it proposes to implement a 250-basis point cap on the total of all ROE adders.

In addition, the FERC revealed in the NPRM that it will address cybersecurity incentives in a separate proceeding. Moreover, in a dissenting opinion, one FERC commissioner indicated that he would be in favor of an additional incentive not included in the NPRM, an incentive for transmission projects needed to meet public policy goals such as state carbon reduction targets.

The NPRM is pending and there is no certainty that the FERC will ultimately adopt these ROE adder proposals after considering stakeholder comments. However, these creative proposals serve as examples of incentives that a regulatory commission can potentially implement to drive utility management behavior toward investing in desirable infrastructure.

5. FERC Staff White Paper on Cybersecurity Incentives

In June 2020, the FERC staff issued a Cybersecurity Incentives Policy White Paper.[11] FERC and the utility industry place an extremely high priority on cybersecurity. FERC staff emphasizes that cybersecurity is an important component of reliability and a vital element in the protection of United States national security interests.

Critical Infrastructure Protection (CIP) reliability standards established by NERC form an effective technical baseline for cybersecurity practices, but have limitations. The staff white paper discusses

[11] *Cybersecurity Incentives Policy White Paper*, A Staff Paper: Federal Energy Regulatory Commission Docket No. AD20-19-000 (June 2020).

augmenting the current CIP reliability standards with an incentives-based approach that encourages utilities to adopt best practices and undertake cybersecurity investments on a voluntary basis to protect their own transmission assets and the bulk electrical system. These incentives could include both ROE and non-ROE incentives.

Among other potential cybersecurity incentives, FERC staff suggests an ROE adder of up 200 basis points, applicable to specific incremental cybersecurity investments. It appears that this 200-basis point cybersecurity incentive would be above and beyond the 250-basis point cap proposed in the ROE incentive NPRM.

If FERC chooses to take action on this staff white paper proposal, it would procedurally need to issue a notice and/or open up a docket. Comments of stakeholders will address whether the cybersecurity ROE adder is appropriate and if the proposed 200 basis point level is enough to incent incremental cybersecurity investment.

Regardless of the ultimate outcome, this potential cybersecurity ROE adder also represents an example of a creative FERC proposal to drive utility management toward investing in desirable infrastructure.

6. State ROE Rewards and/or Penalties

In addition to the federal level, state regulators also have implemented ROE incentives. Some states have done so for several decades. Recurring themes include providing customer benefits through encouraging certain utility management investment behavior.

6.1 Virginia

Virginia provides an example of ROE incentives related to incenting desirable types of generation. The Virginia Electric Utility Regulation Act was enacted in 2007. The law provided for recovery of certain costs via rate adjustment clauses. These costs include costs for new generation facilities, transmission service, demand-side management programs such as peak-shaving and energy efficiency programs, environmental compliance costs, incremental renewable energy costs, vegetation management costs, and costs related to undergrounding electric distribution lines. Some, but not all, of the rate adjustment clauses were to include an ROE adder (or reward) of 100-200 basis points.

The Virginia Corporation Commission implemented this law by approving a series of rate adjustment clauses in subsequent Virginia Power rider cases that continue through the present. The Bear Garden Generating Station, Brunswick County Power Station, and Warren County Power Station are natural gas generation facilities that have separate riders that incorporate an ROE adder of 100 basis points.[12] The biomass conversion rider under which the Altavista, Hopewell, and Southampton coal units were converted to renewable biomass fuel includes an ROE adder of 200 basis points.[13] The Virginia City Hybrid Energy Center is fueled by clean coal and renewable biomass in an advanced circulating fluidized bed technology and has a rider with an ROE adder of 100 basis points.[14] Other riders have been approved

[12] For example, see Virginia State Corporation Commission Final Order in Case Nos. PUE-2014-00103 (April 21, 2015) and PUE-2015-00102 (June 30, 2016) and Virginia State Corporation Commission Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant of §56-596 B of the Code of Virginia (September 1, 2016), 11-17.

[13] For example, see Virginia State Corporation Commission Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant to §56-596 B of the Code of Virginia (September 1, 2016), 12-13.

[14] Ibid., 16.

for solar generation, energy efficiency programs, demand response programs, and undergrounding electric distribution lines but without ROE adders.

6.2. New Jersey

A June 2020 New Jersey energy efficiency and peak demand reduction order provides for ROE rewards and penalties.[15] In this case, the New Jersey Board of Public Utilities (BPU) implemented multi-year energy efficiency and peak demand reduction programs for New Jersey electric and natural gas utilities in response to the New Jersey Clean Energy Act of 2018 that identified customer benefits associated with such programs.

The BPU adopted a staff-proposed framework that identified certain quality performance indicators as desirable. The BPU found that an ROE adder of up to 50 basis points for achieving 110-150% of the quality performance indicators in year 5 along with a reduction in ROE of up to 200 basis points for meeting only 50-90% of the quality performance indicators represents a reasonable range of incentives and penalties. Both the adder and penalty scale in linear fashion over the identified ranges. The achievement of 90-110% of the quality performance indicators would represent compliance and result in no reward or penalty to the base ROE. The ROE adder or penalty would be applicable only to the utility's energy efficiency and peak demand reduction expenditures, not to the entire rate base. Based on the legislation, rewards or penalties will not apply during the first five years of the programs, with year six rewards and penalties based on performance metrics during year five.

6.3. Maine

In February 2020, the Maine Public Utilities Commission (PUC) concluded two investigations into the rates and revenue requirements as well as metering and billing issues of Central Maine Power by imposing a 100-basis point ROE penalty based on sub-standard customer service and poor management.[16] The PUC concluded that the company's customer service had reached unreasonable and inadequate levels, which was considered evidence of management inefficiency and imprudence. The PUC found that the company was not meeting customer service standards in call-handling or staffing.

Specifically, the PUC observed that numerous customer complaints and public skepticism increased over a two-year period in part emanating from the rushed implementation of an unfamiliar and error-prone software program. The PUC found that compressing the schedule for critical testing of the software was imprudent, meaning that the company did not act under a course of conduct that a capably managed utility would have followed in light of existing and reasonably knowable circumstances.

The ROE penalty will be effective for at least 18 months. The company can mitigate the penalty after 18 months by complying with a set of customer service quality metrics related to call center operations, bill-error rate, and minimizing estimated bills.

[15] New Jersey Board of Public Utilities Order Directing the Utilities to Establish Energy Efficiency and Peak Demand Reduction Programs, Docket Nos. Q019010040, Q019060748, and Q017091004 (June 10, 2020).
[16] Maine Public Utilities Commission Orders on Investigation into Rates and Revenue Requirements of Central Maine Power Company, Docket No. 2018-00194 (February 19, 2020) and Investigation into Central Maine Power Company's Metering and Billing Issues, Docket No. 2019-00015 (February 26, 2020).

6.4 Pennsylvania

Several Pennsylvania rate case orders provide examples of ROE rewards for management efficiency. A 1986 law provides a directive that the Pennsylvania Public Utility Commission (PUC) consider management efficiency including effectiveness, adequacy of service, operating efficiency, encouragement of conservation, and load management of each utility when determining just and reasonable rates. Utilities are permitted to request ROE premiums for above-average management efficiency. The Pennsylvania Public Utility Commission (PUC) has the authority to approve or reject the request.

In 1994, the PUC granted West Penn Power a 25-basis point adder because the company promoted and accomplished cost efficiencies in several operational aspects particularly environmental compliance, but rejected a similar request in 1995.[17] In 2008, the PUC approved a 22-basis point ROE adder for Aqua Pennsylvania, citing laudable managerial performance related to its water quality, customer service, and a low income program.[18] Also, the PUC authorized a 12-basis point premium for PPL in 2012 in recognition of its exemplary management performance.[19]

6.5 Indiana

A 2016 Indiana rate case order provides an example of an ROE penalty for perceived management inefficiency.[20] The Indiana Utility Regulatory Commission (URC) found a 15-basis point ROE penalty was appropriate for Indianapolis Power & Light.

The URC noted that it had been critical of the company's management decisions over a multi-year period, particularly related to its presentation of environmental compliance cost-benefit analysis, the bid process used to determine the best estimate for constructing a natural gas plant, and public safety and reliability concerns related to maintenance and operation of its downtown Indianapolis network. The URC expressed a desire to send a clear and direct message to utility management concerning the need for improvement in provision of its utility service and considered the 15-basis point penalty an appropriate adjustment.

6.6 Florida

The Florida Public Service Commission (PSC) has occasionally granted ROE performance adders for laudable management performance and established ROE penalties for mismanagement. Gulf Power was awarded a 10-basis point ROE adder in 1982, while a 50-basis point penalty was imposed for mismanagement in 1992.[21] Then in 2002, Gulf Power received a 25-basis point adder based on management performance.[22] Recent requests for ROE adders by utilities have not been ruled upon by the PSC due to rate case settlements.

[17] Pennsylvania Public Utility Commission Opinions and Orders, Docket Nos. R-00942986 (December 29, 1994) and R-00922378 (March 19, 1995).
[18] Pennsylvania Public Utility Commission Opinion and Order, Docket No. R-00072711 (July 31, 2008).
[19] Pennsylvania Public Utility Commission Opinion and Order, Docket No. R-2012-2290597 (December 5, 2012).
[20] Indiana Utility Regulatory Commission Order in Cause Nos. 44576 and 44602 (March 16, 2016).
[21] Florida Public Service Commission Orders No. 9628 (1982) and 23573 (1992).
[22] Florida Public Service Commission Order No. PSC-02-0787-FOF-EG (2002).

6.7 Illinois

In October 2011, the Illinois Legislature signed the Energy Infrastructure Modernization Act into law. The law was designed to modernize and upgrade the electric system and encourage smart grid investment including distribution automation, substation upgrades, and smart meters. The law set reliability and performance metrics to be achieved over a ten-year period. The metrics targeted standard metrics of SAIFI, SAIDI, and CAIDI[23] and improvement in number of customers who exceed service reliability targets, as well as reductions in estimated bills, inactive meters, unaccounted for energy, and uncollectible expense.

The consequences of not meeting the targeted performance metrics is an ROE penalty of five to seven basis points per goal. Over the course of several years, utilities largely met the targets. However, the observed performance metrics in several years resulted in ROE penalties of five or six basis points as determined by the Illinois Commerce Commission.[24]

6.8 Nevada

In the mid-2000s, the Nevada Public Utilities Commission (PUC) incorporated a 500-basis point adder into its rules to improve the attraction of demand-side management (DSM) investments.[25] To be eligible for the adder, demand-side management projects passed through a comprehensive vetting process by the utility, the PUC's DSM Collaborative, and then parties participating in the utility's integrated resource planning process. The 500-basis point adder was intended to give DSM planning an advantage in competing for the utility's limited financial resources.

7. Final Remarks

This Annex 2 provides some context to regulators around the world, especially in emerging economies, about how ROE incentives may be used in the tariff-setting process. As demonstrated by the forgoing United States examples, there are many uses of ROE incentives to benefit customers, including encouraging investments in certain types of generation, energy efficiency programs, peak demand reduction programs, reliability, technological innovation, cybersecurity, environmental compliance and upgrades, advancement of decarbonization objectives, efficient management performance, customer service enhancements, improvements in outage frequency and duration, electric transmission, distribution automation, and smart grid modernization.

[23] SAIFI is System Average Interruption Frequency Index; SAIDI is System Average Interruption Duration Index; and CAIDI is Customer Average Interruption Duration Index.
[24] Illinois Commerce Commission website, Financial Analysis Division Rate Case History Report, Formula Rates tab.
[25] Nevada Administrative code, chapter 704, section 9523, NAC 704.9523(3)(e)(4).

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