Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below)	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low While there may be some exposure to Challenged Sources, it is not a cause for concern	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates May show somewhat greater volatility in the regulatory regime(s)	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market May show decided volatility in the regulatory regime(s)	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

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Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

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Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[17] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

[17] See paragraph at the end of this section for approaches to Hybrid HoldCos

See also those factors noted in "Notching for Structural Subordination of Holding Companies"

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses [18] If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due to the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated The degree of separateness may be greater or smaller and is assessed on a case-by-case basis, because situational considerations are important.

One area we consider is financing arrangements For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt

While most of the regulatory barriers to cash movement are very real, they are not absolute Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers Typically, most entities in US utility families (including HoldCos and

[18] A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section

OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub-sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC) LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure) LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities, and performing other supply-related activities, such as customer billing and metering The rates or tariffs for the totality of these activities are set by the relevant regulatory authority Many integrated gas utilities are national in scope

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. This typically means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator Companies that have been included in this group include certain generation companies that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology.[19]

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs Transmission-only utilities in most parts of the world other than the US have typically been rated under a different methodology.[20]

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company The operating subsidiaries of Utility HoldCos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

[19] For more information, see our methodology that describes our general approach for assessing unregulated utilities and unregulated power companies A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section

[20] For more information, see our methodology that describes our general approach for assessing regulated electric and gas networks. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section

Appendix D: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance on notching corporate instrument ratings based on differences in security and priority of claim, including a one notch differential between senior secured and senior unsecured debt.[21] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US Wider notching differentials between debt classes may also be appropriate in speculative-grade issuers.[22]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two-notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one-notch differential between US first mortgage bonds and the senior unsecured rating For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been pervasive in the past. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follow the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling

21 A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

22 For more information, see our cross-sector methodology that describes general principles related to loss given default for speculative-grade companies A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section

legislation As a result, accounting treatment may vary. In most states, utilities have been required to consolidate securitization debt under GAAP, even though it is technically non-recourse

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Appendix E: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following. to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received) When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and we may treat each particular circumstance differently Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow

» Excess Reserve Capacity: In some jurisdictions, there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility In addition, PPAs are not typically considered debt for cross-default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case, we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6 In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases) This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility The discount rate used will be our estimate of the cost of capital of the utility

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Publications

Credit ratings are primarily determined by sector credit rating methodologies. Certain broad methodological considerations (described in one or more cross-sector rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments An index of sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings, please click here.

For further information, please refer to *Rating Symbols and Definitions*, which is available here

Analyst Contacts.

BUENOS AIRES +54 11 5129 2600

Daniela Cu... 54 5129 261
...resident ...
da... ...

TORONTO 416 214 1635

Gevin MacF... 41... 4 ...
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LONDON +44 20 7772 5454

Dougla... Seg... +44 20 ... 2 ... 34
...

HONG KONG +852 2551 ...

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SINGAPORE ... 6398 8308

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TOKYO 81 ... 5408 4100

Mihoko ... 8 ... 087
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Mariko ... 81 ... 087 ...

Report Number: 1072530

Author
Michael G. Haggarty

Production Associate
Masaki Shiomi

MOODY'S
INVESTORS SERVICE

U.S. Utilities, Power and Gas

Ratings Navigator Companion
Special Report

Navigator for Corporates is a graphical peer comparator that forms part of a series of similar tools being introduced across Fitch.
Information on the formal rating criteria that underlie Fitch's corporate ratings can be found in Fitch's *Corporate Rating Methodology* Master Criteria, dated May 28, 2014.

Related Research
Introducing Rating Navigator for Corporates (November 2014)

Analysts
Shalini Mahajan
+1 212 908-0351
shalini.mahajan@fitchratings.com

Glen Grabelsky
+1 212 908-0577
glen.grabelsky@fitchratings.com

Sector and Subsectors: This report presents the key peer comparator elements observed or expected for U.S. utilities, power and gas (UPG) companies. Fitch's rating coverage of investor-owned UPG companies in the U.S. includes companies with a wide range of risk profiles and business interests. These include both utilities with monopoly or market-dominant positions that are typically subject to tariff regulation and regulatory oversight of their service levels and terms of service, and companies that do not have a monopoly market position and are exposed to market competition. Finally, there are utility parent companies with varied holdings of companies engaged in regulated and competitive businesses.

Key Factors: The Sector Risk Profile defines and groups companies operating in the sector into a "natural rating territory" based on Fitch's view of the inherent risk profile of the industry. Each company's overall risk profile generally does not stray too far from this rating range. After assessing the Operating Environment, then Management and Corporate Governance, the Navigator examines four Sector-Specific factors for given rating levels. Finally, three Financial Profile factors help capture financial attributes commensurate with particular rating categories.

Sector Risk Profile

Rating Range: Regulated utilities, which include integrated electric utilities, electric transmission and distribution utilities, regulated electric transmission companies and local gas distribution utilities can be rated up to the 'A' category. Utility parent companies that own a mix of regulated and nonregulated businesses also tend to be rated up to the 'A' category, while the nonregulated businesses, such as competitive generators, retail electric and gas providers, and propane distributors rarely exceed the 'BBB' rating category.

Sector-Specific Key Factors

Regulation: This Key Factor assesses the regulatory framework that a utility operates in. The nature of tariff-setting mechanisms, consistency in rule-making and regulatory outcomes, and the level of political influence exerted on regulations have a significant bearing on the stability of cash flows. State regulatory frameworks do not affect a competitive generator by a similar magnitude, yet regulatory and political interests can still interfere with market mechanisms.

Market and Franchise: This factor considers customer mix, economic health and vibrancy of a service territory, and sensitivity of sales and cash flows to extreme weather or disaster disruptions. Location plays an important role for a competitive generator since power prices are driven by the demand supply balance, fuel mix and prices of key fuel inputs in a region.

Asset Base and Operations: This factor assesses a company's physical infrastructure with respect to age, technology, cost competitiveness and reliability of operations that may influence its relative price competitiveness and drive capital reinvestment needs.

Commodity Exposure: This factor measures the insulation provided in regulated tariff mechanisms against variability in commodity costs. For a competitive generator, this factor assesses the hedging practices employed to mitigate the effect of fuel and selling price volatility.

Sector Risk Profile

The overall risk profile of the sector is characterized by strong defensive qualities since the demand for electricity and natural gas tends to be relatively noncyclical and inelastic, in particular for residential customers. The sector exhibits high capital intensity. New electricity generation and transmission usually involves significant capital investment, often with long lead times. Electricity and gas distribution services typically require significant maintenance capital expenditure to ensure reliability and safety of the service. During investment cycles, these businesses can be significantly FCF negative, thus requiring external financing to fund expansion and replacement capital expenditure.

State regulation has a material bearing on the risk profile of the sector as certain states in the U.S. have deregulated electricity generation while the rest continue to follow the legacy structure of fully vertically integrated regulated utilities. Companies that provide utility service with monopolistic service territories are typically subject to tariff regulation and regulatory oversight of their service levels and terms of service, and generate relatively stable and predictable cash flow. Competitive generation companies bear the full risk of market competition and can be exposed to significant price and volume risk, although these risks can be substantially mitigated by long-term fuel and power sales agreements and/or effective hedging.

The rated issuers in Fitch's U.S. investor-owned UPG sector exhibit a wide range of participants from multi-utility giants to smaller, specialized participants. As such, this sector exhibits both segmentation and diversity of business risk profiles.

Given the sector risk profile described above, the following summary indicates U.S. UPG risk characteristics commensurate with different rating categories for the Issuer Default Ratings (IDRs).

Fully Regulated Utilities: 'A+' to Speculative Grade

These businesses provide electric and/or gas services in natural monopolies and are subject to conducive tariff regulation. There exists significant regulatory oversight regarding costs of service, operating performance, financing and other strategic activities.

These include electric transmission and distribution utilities, vertically integrated electric utilities, regulated transmission companies and local gas distribution companies. These companies bear little or no commodity sensitivity and relatively modest cyclical or volumetric risk, and generate relatively stable and predictable cash flow profiles.

Competitive Generation: 'BBB+' to Speculative Grade

These businesses do not have a market monopoly position and are thus exposed to market competition.

These include competitive power generators, retail electric and gas providers, and propane distributors. These companies are subject to greater commodity sensitivity, market risk or cyclical variation.

Related Criteria

Corporate Rating Methodology — Including Short-Term Ratings and Parent and Subsidiary Linkage (May 2014)

Utility Parent Companies: 'A+' to Speculative Grade

These holding companies by themselves are rated lower than their operating subsidiaries, but when they have varied holdings, as described above, company-specific traits may provide rating uplifts to the 'A' category.

These companies may be passive investors or operationally integrated with their operating subsidiaries, providing centralized treasury activities, and operational or administrative services. The overall earnings stream is a function of underlying business portfolio of utility and/or non-utility activities.

Operating Environment, Management and Corporate Governance

Please see Appendix I.

Sector-Specific Key Factors

Regulation

Regulation is a key credit risk factor for utilities. The regulatory framework across Fitch's rated companies' universe varies widely based on market structure, tariff-setting mechanisms and political influence. A benign and supportive regulatory environment could support a rating uplift, all other conditions being equal, even when credit metrics are not in line with those of the relative rating level. Conversely, an extended period of adverse or penalizing regulatory actions could lead to lower ratings given regulatory constructs often tend to be sticky and could take a long time to turn around.

Regulation: Sub-Factors

	Degree of Transparency and Predictability	Timeliness of Cost Recovery	Trend in Authorized Return on Equity (ROE)	Mechanisms Available to Stabilize Cash Flows	Mechanisms Supportive of Creditworthiness
'a' Category	Track record of transparent and predictable regulation	Minimal lag to recover capital and operating costs	Above-average authorized ROE	Revenues fully insulated from variability in consumption	Effective regulatory ring-fencing
'bbb' Category	Generally transparent and predictable regulation with limited political interference	Moderate lag to recover capital and operating costs	Average authorized ROE	Revenues partially insulated from variability in consumption	Effective regulatory ring-fencing or minimum credit worthiness requirements
'bb' Category	Poor or uncertain track record of regulation and high political interference	Significant lag to recover capital and operating costs	Significantly below-average authorized ROE	Revenues fully exposed to variability in consumption	Limited regulatory ring-fencing or minimum credit worthiness requirements
'b' Category	Hostile regulatory or political jurisdiction or frequent regulatory interference in market based mechanisms	Material delays in recovering capital and operating costs	Absence of regulatory ROE	Revenues fully exposed to declining consumption	Absence of minimum credit worthiness requirements

Source: Fitch.

State regulatory frameworks do not affect a competitive generator by the same magnitude as they do for a regulated utility. Regulatory and political interests can still interfere with market mechanisms and raise the risk profile of all deregulated power plants in a region. For a utility parent company, a multi-utility portfolio across different state jurisdictions can help diversify the regulatory risk.

Fitch assesses the following aspects of regulation.

Degree of Transparency and Predictability

Consistency in regulatory framework and predictability in decision making is most beneficial to the credit profile of a regulated utility. A historically supportive state regulatory environment and lack of controversial future regulatory events can help support a low credit risk for a utility. Regulatory risk increases as the framework becomes less predictable due to factors such as frequent changes in tariff-setting mechanisms, increased political and/or legislative interference and untested new commissioners. A period of rising unit costs that may necessitate frequent or large base rate increases typically increases the risk of populist regulatory decisions.

Fitch views rate-regulated electric transmission companies as having low regulatory risks, such as those regulated by the Federal Energy Regulatory Commission (FERC), since a national regulator is likely to apply a consistent approach when regulating various entities across the country, free of local political issues that can influence a state regulator.

Timeliness of Cost Recovery

Tariff-setting mechanisms that allow utilities to recover costs in a manner that limits regulatory lag are favorable to their risk profile. A supportive state regulatory environment typically provides for periodic rate-adjustment mechanisms for variable operating costs, primarily fuel and purchased power, and certain capital costs with frequent forward-looking adjustments that provide a full and timely recovery of costs and a return on capital consistent with the level of risk incurred by the utility. In general, the higher the share of total revenues collected through effective rate-adjustment mechanisms, rather than base rate filings, the greater the expected cash flow stability.

Alternatively, if a significant proportion of a utility's costs of service are recovered through periodic base rate retail tariff adjustments, greater cost recovery lags are likely to occur. Use of historical rate base and test years, exclusion of construction work in progress from rate base, long time frames for final rate decisions and the inability of the utility to implement interim rate increases can further accentuate regulatory lag.

Mechanisms Available to Stabilize Cash Flow

A regulatory framework that insulates revenues from volume risk, variability in weather and volatility of commodity prices contributes to enhanced revenue and cash flow visibility. Some utility tariff structures are relatively or absolutely indifferent to sales volumes due to declining use per customer or mild weather through partial- or full-volume decoupling mechanisms. Such mechanisms can enhance cash flow stability and are supportive of the risk profile of the utility.

Mechanisms Supportive of Creditworthiness

Effective regulatory ring-fencing mechanisms and minimum creditworthiness requirements, such as prescribed regulatory capital structure or dividend restrictions, can support a minimum creditworthiness of utilities. This assumes greater significance in a multi-utility family and helps isolate the credit of the utility from a weaker parent holding company and/or other weaker affiliates. However, such restrictions could lower the cash flow predictability for the parent holding company because there is less assurance of subsidiary dividend.
Ring-fencing provisions may include:

- Separate financing, including no cross-default or cross-acceleration conditions, and no external guarantees.
- Separate liquidity (cash management, availability under credit facilities, cash pooling, treasury management).
- Covenanted dividend restrictions.
- Covenanted, or company policy, mitigating related-party transactions, and other potential conflicts of interest (e.g. feedstock, shared services).
- Noncommon ownership.
- Separate management, and active independent board representation consistent with a separate company.

Market and Franchise

Customer mix, economic health and vibrancy of the service territory, and sensitivity to extreme weather or disaster disruptions can have a meaningful impact on a regulated utility's risk profile. A greater exposure to the residential customer segment warrants a good degree of demand stability, while higher exposure to the industrial segment implies greater volume volatility during an economic cycle. Stagnant or decreasing volume of sales could render the revenue too low to cover the high fixed costs of providing utility service. The nascent but growing trends of energy efficiency and distributed generation could pressure a utility's sales volumes in certain regions. Alternatively, growth in sales can have favorable results for a utility's gross margins.

Market and Franchise: Sub-Factors

	Market Structure	Consumption Growth Trend	Customer Mix	Geographic Location	Supply Demand Dynamics
'a' Category	Well-established market structure with complete transparency in price-setting mechanisms	Economically vibrant market or service territory with strong sales growth	Favourable customer mix	Favorable location or high geographic diversity	Beneficial outlook for prices/rates
'bbb' Category	Established market structure, but some level of uncertainty in price-setting mechanisms	Customer and usage growth in line with industry averages	Less diversified customer base	Beneficial location or reasonable locational diversity	Moderately favourable outlook for prices/rates
'bb' Category	Still evolving market structure and uncertain price-setting mechanisms	Exposure to declining usage or volumes or self-generation	High concentration of customers in cyclical industries	High sensitivity to extreme weather or disaster disruptions	Uncertain outlook for prices/rates
'b' Category	High risk to market structure from regulatory or political interference	Rapidly shrinking market or service territory and falling unit consumption	High concentration to risky, less creditworthy customers	High exposure to event risk	Extremely unfavorable outlook for prices/rates

Source: Fitch.

The deregulated power markets in the U.S. are very regional in nature. The physical location of a competitive generator's power generating fleet is a key variable in determining its profitability and cash flows since regional power prices are driven by the demand supply balance, fuel mix, and prices of key fuel inputs in a region. Market structures vary from one region to another, from the energy-only market in the Electric Reliability Council of Texas to a combination of energy and auction-based capacity markets in the PJM and the New York and New England regions. A three-year forward looking capacity market in the PJM region provides higher visibility to the revenue of a power plant operating in that region. The physical location of a deregulated power plant also defines its proximity to fuel sources, load, and regional transmission dynamics, thus influencing its competitive position in its region.

Geographic diversification can provide a competitive generator protection against regional power price swings that result from demand/supply imbalances, volatility in the price of marginal fuel costs, and other factors such as weather, availability of renewable generation, or transmission constraints.

For a parent holding company, diverse subsidiary cash flows can be beneficial to the credit profile. Holding companies receiving regular upstream cash flows from numerous subsidiaries, with none contributing to more than 15% of parent-level cash sources and few constraints on upstream cash distributions may result in a stronger credit profile than any of their individual subsidiaries.

Asset Base and Operations

Asset base and operations focuses on a qualitative and comparative (peer group) assessment of a company's physical infrastructure that may influence its relative price competitiveness, both current and expected, and drive capital reinvestment needs.

Age and quality of a utility's infrastructure will drive the need to invest in capital improvements of fixed assets. Concentration of generation assets of a utility in a specific fuel class such as coal can expose it to higher compliance-driven capital expenditures and put pressure on retail rates. New generation projects in relatively capital intensive or innovative technologies entail completion risks. All these factors can result in financial stress if there are delays in cost recovery or recovery disallowances. For utilities, precertification of system improvements by regulators, fixed-price construction contracts, accommodative rate tariff mechanisms such as concurrent cash return on construction work in progress, and demonstrated organizational capability to manage large capital projects serve to limit completion and delay risks.

Fitch considers a variety of operating metrics when conducting a review of operations of a regulated utility. These metrics include the frequency and duration of service disruptions for transmission and distribution operators, and unit availability and equivalent forced outage rates for utilities that generate electricity. A record of poor service reliability, frequent service outages, and prolonged restoration of service as a result of weather and other disaster events can contribute to customer dissatisfaction and increase political and regulatory risks. Service disruptions may result in higher purchased power costs, operating costs, or capital spending requirements that may or may not be readily recoverable from customers. Regulated utilities that do not own their own generation are generally perceived to be at the lower end of the scale of operational complexity within the range of utilities' operational risks.

For a competitive generator, Fitch takes into consideration the size and diversity of the generating fleet when evaluating the underlying quality of the portfolio. This evaluation includes fuel mix, geographic location and overall position along the dispatch curve. Scale and scope are important factors since a diversified portfolio of plants tends to lower operating risk and facilitate a broader, more flexible marketing strategy. Ownership of multiple generating plants provides a company with cost synergies and more effective coordination of routine maintenance procedures. Companies that rely on a single or smaller number of units are more exposed to cash flow volatility resulting from an unexpected outage, significant repair costs, and replacement power costs to honor any existing contractual supply obligations.

The variable fuel and operating costs per unit of power determine a power plant's ranking on the dispatch curve within a competitive regional market. The plants with the lowest variable costs are dispatched first and exhibit high capacity utilization and less volatile cash flows. A generator's location far from the center of consumption makes its revenues contingent on availability of transmission capacity. A generator's exposure to environmental compliance costs, with regard to both existing and expected regulations, can significantly affect its operating costs and capital reinvestment needs. This could significantly affect the cash flow and risk profile of the generator to the extent the higher costs cannot be passed through to counterparties in existing contracts or recovered via higher market prices.

Asset Base and Operations: Sub-Factors

	Diversity of Assets	Operations Reliability and Cost Competitiveness	Exposure to Environmental Regulations	Capital and Technological Intensity of Capex
'a' Category	High-quality and/or large-scale diversified assets	Track record of reliable, low cost operations	No exposure to environmental regulations	Low levels of reinvestment requirements
'bbb' Category	Good quality and/or reasonable scale diversified assets	Reliability and cost of operations at par with industry averages	Limited or manageable exposure to environmental regulations	Moderate reinvestments requirements in established technologies
'bb' Category	Small size and limited diversification	Below-average system reliability and cost structure	Significant exposure to environmental regulations	Reinvestment concentrated in capital-intensive or unproven technologies
'b' Category	Low quality, small size and highly concentrated assets	Poor system reliability and disadvantageous cost structure	Merchant generator with a material exposure to highly polluting technology	High exposure to execution risk for projects involving large outlays or unproven technologies

Source: Fitch.

Commodity Exposure

The vast majority of U.S. integrated utilities have some form of periodic revenue adjustment mechanism that offsets changes in fuel costs, and therefore limits fluctuation in cash flow related to fuel price volatility. However, there is considerable variation in the timing and efficacy of these adjustments. Regulators' attempt to minimize rising consumer rates through fuel cost recovery deferrals can lead to gradual deterioration of utility creditworthiness. The utilities with no or limited commodity exposure include electric transmission companies, electric transmission and distribution utilities, and local gas distribution utilities.

Competitive generators are sensitive to the price and availability of fuel sources and market trends in wholesale prices. Companies in the sector with more stable and predictable cash flows generally hedge their net revenues through physical or derivative contracts. Generators that adhere to long-term contracts with high-quality counterparties in combination with no or limited fuel risk and low variable costs can produce highly stable cash flows as long as they ensure high unit availability and reliability metrics. Generators that operate without a high percentage of contract cover and have facilities with relatively high marginal costs of operation relative to others in the same market have the greatest cash flow volatility.

An unhedged commodity strategy may be employed by speculative-grade companies that cannot economically hedge as a result of limited financial capability to meet collateral requirements. This strategy may also be adopted during periods of low commodity prices as a form of speculation on future market direction. Companies that engage in proprietary trading and speculate on the direction of energy prices can incur substantial market and liquidity risks.

Commodity Exposure: Sub-Factors

	Ability to Pass Through Changes in Fuel	Underlying Supply Mix	Hedging Strategy
'a' Category	Complete pass through of commodity costs	Extremely low cost and flexible supply	Highly captive supply and customer base
'bbb' Category	Limited exposure to changes in commodity costs	Low variable costs and moderate flexibility of supply	Long-term supply and sales contracts with credit worthy counterparties
'bb' Category	Inability to pass through all changes in commodity costs	High variable costs and limited flexibility of supply	Medium-term hedging strategy for supply and sales
'b' Category	High exposure to commodity price changes	Extreme variability in costs and minimal flexibility of supply	Minimal hedging of supply and sales or highly speculative trading positions

Source: Fitch.

Financial Risk Profile

The quantitative aspect of Fitch's corporate ratings focuses on an issuer's financial profile and its ability to service its obligations from a combination of internal and external resources. The sustainability of these credit protection measures is evaluated over a period of time — using both actual historical numbers, but more importantly, Fitch's forecasts — to determine the strength of an issuer's debt-servicing capacity and funding ability.

Financial metrics can alleviate only some of the pressures from the Sector Risk Profile and Business Profile characteristics, and do not enable the company to completely insulate itself. Conversely, a company with a strong business profile may be burdened by high leverage, which may exert strong downward pressure on rating levels.

For a regulated utility, tolerance of a weaker financial profile is greater if the weakness results from implementation of a large capital investment program, but the regulatory mechanisms to recover a return on and of that capital investment are largely in place.

Seasonal volatility is a common characteristic for many utilities. It is most pronounced in winter-peaking natural gas local distribution companies (LDC), but it also exists to a lesser extent in summer-peaking electric utilities to meet cooling demand for air conditioning. The seasonality presents manageable credit risks and, more commonly, natural gas LDCs have decoupling mechanisms, which balances their earnings and cash flows apart from volumetric sales.

Winter-peaking gas LDCs experience large seasonal working capital demands for inventory as well as carrying customer receivables. Such demands create temporary seasonal working capital borrowings, which tend to peak in December and pay off by March. Many gas utilities use a September fiscal year to avoid such distortions created by the working capital borrowings. Fitch tends to look at average debt balances over the year as more indicative of leverage rather than the peak level in the December quarter or the trough level in the June quarter.

Profitability

The UPG sector is characterized by large capital investments in long-dated property, plant and equipment. Utilities with extensive capex programs tend to experience long periods of negative FCF during investment peaks due to the time lag between investment and cash flow from related assets. Additionally, dividends are viewed as quasi-fixed payments given utility stocks are predominantly attractive to income seeking investors.

Weak profitability could result from large lag between capital investment and the recovery of it in tariffs. A long-dated, large capital investment program can intensify the impact of regulatory lag on profitability measures. Some utilities benefit from recovery riders that permit a return on and a return of the invested capital during a large-scale infrastructure project.

As a regulated sector, the profitability of utilities is generally below other corporate sectors. Integrated electric utilities tend to receive higher authorized ROE than transmission and distribution utilities, based on the perceived higher risks of maintaining an electric generating fleet, while natural gas LDCs may have a lower ROE still. Profitability comparisons between

Profitability: Sub-Factors

Midpoints	Free Cash Flow	Volatility of Profitability
'aa' Category	N.A.	N.A.
'a' Category	Structurally neutral to positive FCF across the investment cycle	Higher stability and predictability of profits relative to utility peers
'bbb' Category	Structurally neutral to negative FCF across the investment cycle	Stability and predictability of profits in line with utility peers
'bb' Category	Structurally negative FCF across the investment cycle	Lower stability and predictability of profits relative to utility peers
'b' Category	Structurally heavily negative FCF across the investment cycle	Stability and predictability of profits viewed as negative outliers relative to utility peers

N.A. – Not applicable.
Source: Fitch.

utilities can also vary by rate base mix with federally regulated transmission generally receiving higher ROEs.

As noted earlier, Fitch adjusts for seasonal working capital needs and the distortion it creates on leverage, and generally the seasonality is not a ratings factor. Fitch does consider recovery of pass-through items such as gas or purchased power and the frequency of tariff resets to recover higher market prices than those that existed when the rates were set. Monthly or quarterly resets are preferable to annual true-ups, which may result in significant under collection or over collection. Situations where large deferred balances exist and collection is extended over many years place a strain on liquidity and can be problematic for the rating.

Financial Structure

As detailed in Fitch's *Corporate Rating Methodology: Including Short-Term Ratings and Parent and Subsidiary Linkage*, the agency analyzes cash flow and EBITDA-based leverage adjusted for items such as operating leases for long-term assets and nonrecourse utility tariff bonds issued by special-purpose entities. Fitch may also fully or partially deconsolidate nonrecourse subsidiaries that Fitch deems of no strategic importance to the rated parent and having a high likelihood the parent will not extend support to the subsidiary debt in the event of financial stress at the subsidiary level.

Financial Flexibility

Financial Flexibility measures an issuer's ability to meet its debt service obligations and manage periods of volatility without eroding credit quality. The more conservatively capitalized

Financial Structure: Sub-Factors

MIDPOINTS>>>

Midpoints	Lease-Adjusted FFO Gross Leverage (x)	Total Adjusted Debt/ Operating EBITDAR (x)
'a' Category	3.50	3.25
'bbb' Category	5.00	3.75
'bb' Category	6.50	4.75
'b' Category	7 00	6.00

Source: Fitch.

an issuer, the greater its financial flexibility. In general, a commitment to maintaining debt within a certain range allows an issuer to cope better with the effect of unexpected events. This is reflected in the Financial Discipline Sub-Factor.

Other factors that contribute to Financial Flexibility are the ability to revise plans for capital spending, strong banking relationships, the degree of access to a range of debt and equity markets, committed, long-dated bank lines and the proportion of short-term debt in the capital structure. These issues are incorporated in the Liquidity Sub-Factor.

Financial Flexibility: Sub-Factors

Midpoints	Financial Discipline	Liquidity	FFO Fixed-Charge Cover (x)
'aa' Category	Publicly announced conservative financial policy. Track record of strict compliance.	Very comfortable liquidity; no need to use external funding in the next 24 months. Well-spread debt maturity. Diversified sources of funding.	N.A.
'a' Category	Clear commitment to maintain a conservative policy with only modest deviations allowed.	Very comfortable liquidity. Well-spread maturity schedule of debt. Diversified sources of funding.	5.0
'bbb' Category	Less conservative policy, but generally applied consistently.	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.	4.5
'bb' Category	Financial policies in place, but flexibility in applying it could lead to temporary exceeding downgrade guidelines.	Liquidity ratio around 1.0x. Less smooth debt maturity or concentrated funding.	3.5
'b' Category	No financial policy or track record of ignoring it. Opportunistic behaviour.	Liquidity ratio below 1.0x. Overly reliant on one funding source.	2.0

N.A. – Not applicable.
Source: Fitch.

Given the expected negative FCF of many utilities, Fitch assesses internal and external liquidity available to cover the short- and medium-term funding needs of a utility. A liquidity analysis includes a review of near-term debt and credit facility maturities, contingent obligations based on rating or other triggers, and the adequacy of committed backup lines and liquid assets to cover these obligations. The analysis also includes a review of committed capex in the event a utility's access to additional bank debt and/or the capital markets is denied or reduced. Fitch also analyzes the volatility of working capital requirements, including external collateral or other margin requirements, where appropriate. Fitch assesses a utility's track record in reliably and affordably accessing bank and debt capital markets to fund its requirements. Fitch would expect investment-grade names to maintain a healthy liquidity profile at all times.

A more pronounced credit concern is the liquidity needs for managing seasonal working capital needs. While bank lines are generally more than adequate to meet peak borrowing levels, spikes in natural gas prices can absorb available bank line availability very quickly. Most utilities maintain accordion features on their bank facilities for such an event.

Other

Sector Recovery Uplift and Recovery Analysis

For particular utilities, the majority of whose earnings are regulated, that are rated 'BB–' and above, Fitch applies a standard one-notch uplift to the ratings of senior unsecured debt instruments relative to the IDR, representing expected above-average recoveries upon default. Secured debt instruments are generally afforded a two-notch uplift relative to the IDR. The generic sector uplift and the uplift for secured utility instruments is not a bespoke recovery analysis but reflects higher than average recovery expectations for utilities in the case of default based on the following: monopoly-style asset bases, the essential nature of the services, significant barriers to entry, a deep pool of potential bidders for distressed assets, and stronger asset values that are more easily determined. (See Fitch's *Recovery Ratings and Notching Criteria for Utilities*). A bespoke approach is used for companies with IDRs of 'B+' and below.

In jurisdictions where utility instruments benefit from the sector recovery uplift, the obligations of non-utility companies in the energy-related sectors do not receive a similar standard recovery uplift because of their inherent exposure to relatively volatile competitive commodity markets. Consequently, their profitability and resultant capital value are less stable in nature. Examples of such non-utility companies include parent utility companies with material unregulated subsidiaries; competitive generation companies, retail electric and gas providers, and marketing and trading companies; and companies with unusual asset concentrations resulting in potentially greater-than-average volatility in valuations. Within this group, senior unsecured debt ratings are often the same as IDR. As a result, the ratings of parent-level obligations would likely be at least one-notch lower than the subsidiary obligations reflecting the effective subordination.

IDRs Within Corporate Groups

If affairs within a corporate group are managed in a way that supports some separation of affiliates or subsidiaries, or if regulatory mechanisms provide an active and timely separation of regulated from unregulated operations, individual issuers may be recognized as discrete credit risks and assigned distinct IDRs on a "bottom-up" approach. In such cases, IDRs can vary within a corporate family.

When there is a wide disparity in the individual credit profiles, Fitch typically constrains ratings of stronger issuers due to the risks of common ownership and affiliation to a significantly weaker parent or exposure to risks of a weaker affiliate. Conversely, a stronger parent company may provide special forms of credit enhancement or liquidity support, which may raise or lower the otherwise standalone ratings of the entity. (See *Corporate Rating Methodology: Including Short-Term Ratings and Parent and Subsidiary Linkage*).

The relationship of IDRs within corporate groups is not static. Changes in the business portfolio or business strategy, capital structure, leverage, acquisitions, and corporate reorganizations, among other analytical considerations, often cause Fitch to change IDRs, affecting the ratings of all of the instruments within the debt structure

Fitch's notching of parent utility holding company debt considers the legal, regulatory, and bankruptcy framework applicable in the jurisdiction, including whether the business and financial affairs of utility parent companies are subject to regulatory supervision or charter limitations, and the possibility of bankruptcy consolidation of the debts of the utility and its parent holding company.

Limitations

This report outlines indicative factors observed or extrapolated for rated issuers. Ratio levels refer to the mid-point of a through-the-cycle range, and actual observations are likely to vary from these. Certain subsectors may contain a small number of observations overall, or at any given rating category. Where no observations currently exist, guidelines for a category are extrapolated based on Fitch judgment. The relative importance of factors will vary substantially over time both for a given issuer and between issuers, based on relative current significance agreed upon by the rating committee. The factors give a high-level overview and are neither exhaustive in scope nor uniformly applicable. Additional factors will influence ratings particularly where group relationships constrain or enhance a rating level.

Appendix I: The Operating Environment

Operating Environment

The Operating Environment (OE) attempts to reflect graphically the impact on the issuer's profile of the wider context in which it operates, irrespective of its sector. This includes the broad range of factors we look at in assessing the impact of country risk on corporates. The OE is mostly relevant for companies in emerging markets and summarizes in one indicator the attributes described in the Special Report *Rating Emerging Market Corporates*, dated April 2011. More details on the OE are contained in the report *Introducing Rating Navigators for Corporates*, dated October 2014.

The OE is a blend of three sub-factors: Economic Environment, Financial Access, and Systemic Governance. The overall assessment of the OE based on these sub-factors follows the same rule as for the other key factors. When Systemic Governance is the weakest of the three, it is likely to be given a higher relative importance.

The Economic Environment (EE) incorporates Fitch's views on key macro variables that may affect a corporate's fundamental credit strengths, such as the stage of economic development, economic growth expectations and the relative stability or volatility of the economy as a whole. Issuers operating solely within the same country will receive a score under this factor equal to the country's EE. The assessment will take a blended view of the operating environment for corporates that operate in various geographies. An issuer's Financial Access (FA) score is a combination of the strength of its local financial system (both banks and capital markets) as reflected in the Financial Market Development score of the relevant country, of its own level of access to local funding and of its track record and ability to access international financial markets and institutions on a sustainable basis.

An issuer with good local access but limited access to international funding gets the same score as the Financial Market Development score of its local market. The extent of the ability to tap international markets or banks on an unsecured basis defines how much the issuer can detach itself from the strength of its local financial market.

Each country's Systemic Governance score is based on a weighted average of the World Bank's Voice and Accountability, Political Stability, Ease of Doing Business, Control of Corruption, Government Effectiveness and Rule of Law indicators (by increasing order of importance). An issuer will generally receive the score of the country in which its headquarters are located.

Poor individual governance at issuer level (even if it may be typical for the country), would not be picked up in Systemic Governance but in the issuer-specific Management and Corporate Governance factor.

In practice, an OE of 'a' or above indicates an environment which will not have a material impact on credit profiles. OEs of 'bbb' would only suggest a weakness for companies in the strong investment-grade rating categories, while an OE in the 'bb' range would start to moderately shape credit profiles in the lower investment-grade ranges as well.

Management and Corporate Governance

The company-specific Management and Corporate Governance Factor is composed of four sub-factors, Management Strategy, Corporate Governance, Group Structure and Financial Transparency.

Sub-Factor: Management Strategy

Fitch considers management's track record in terms of its ability to create a healthy business mix, maintain operating efficiency, and strengthen its market position. Financial performance over time notably provides a useful measure of management's ability to execute its operational and financial strategies.

Corporate goals are evaluated centering upon future strategy and past track record. Risk tolerance and consistency are important elements in the assessment. The historical mode of financing acquisitions and internal expansion provides insight into management's risk tolerance.

Sub-Factors: Governance Structure, Group Structure and Financial Transparency

The three other sub-factors address different aspects of the general issue of Corporate Governance. The purpose of assessing Governance Structure is to assess whether the way effective power within an issuer is distributed prevents (or conversely makes more likely) potential problems of a principal agent (for example, management extracting value from the shareholders or bondholders for its benefit) or principal-principal nature (for example, a majority shareholder extracting value from minority shareholders or bondholders).

Elements to take into consideration are notably the presence of effective controls for ensuring sound policies, an effective and independent board of directors, management compensation, related-party transactions, integrity of the accounting and audit process, ownership concentration and key-man risk.

Corporate Governance operates as an asymmetric consideration. Where it is deemed adequate or strong, it typically has little or no impact on the issuer's credit ratings, i.e. it is not an incremental positive in the rating calculus. Where a deficiency which may diminish bondholder protection is observed, the consideration may have a negative impact on the rating assigned. Fitch's approach to evaluating corporate governance is described in the Criteria Report *Evaluating Corporate Governance – Country and Issuer-Specific Considerations*.

The Corporate Governance sub-factor focuses on the structural aspects of governance, in particular board of directors' characteristics and ownership structure.

Group Structure and Financial Transparency assess how easy it is for investors to be in a position to assess an issuer's financial condition and fundamental risks. These aspects are somewhat linked to Corporate Governance as high-quality and timely financial reporting is generally considered by Fitch to be indicative of robust governance. Likewise, publishing intentionally inaccurate or misleading accounting statements is symptomatic of deeper flaws in an issuer's governance framework. The public exposure of techniques that subvert the spirit of accepted accounting standards or, worse yet, are designed to mask fraudulent activity can undermine investor confidence.

Management and Corporate Governance: Sub-Factors

Category	Management Strategy	Governance Structure	Group Structure	Financial Transparency
'aa'	Coherent strategy and very strong track record in implementation.	No record of governance failing. Experienced board exercising effective check and balance to management. No ownership concentration.	Transparent group structure.	Financial reporting of exceptionally high standards.
'a'	Coherent strategy and good track record in implementation.	Experienced board exercising effective check and balances. Ownership can be concentrated among several shareholders.	Group structure shows some complexity but mitigated by transparent reporting.	High-quality and timely financial reporting.
'bbb'	Strategy may include opportunistic elements but soundly implemented.	Good governance track record but effectiveness/independence of board less obvious. No evidence of abuse of power even with ownership concentration.	Some group complexity leading to somewhat less transparent accounting statements. No significant related-party transactions.	Good quality reporting without significant failing. Consistent with the average of listed companies on major exchanges.
'bb'	Strategy generally coherent but some evidence of weak implementation.	Board effectiveness questionable with few independent directors. Key-man risk from dominant CEO or shareholder.	Complex group structure or non-transparent ownership structure. Related-party transactions exist but with reasonable economic rationale.	Financial reporting is appropriate but with some failings (e.g. lack of interim or segment analysis).
'b'	Strategy lacking cohesion and/or some weakness in implementation.	Poor governance structure. Ineffective board with no or only token independent directors. Decision-making in the hands of one individual.	Highly complex group with large and opaque related party transactions or opaque ownership structure.	Defective financial reporting. Aggressive accounting policies.
'ccc'– for the Generic Navigator only	Strategy visibly failing, major transformation required to avoid company failure, with "no better than evens chance" of success	Track record of failed governance practices. Profound instability/ vacancies in board membership. Decision-making dysfunctional and damaging to strategic progress	Group structure sufficiently complex or compromised (disputed ownership, disputed transactions) to materially impair strategic and financial progress.	Sustained absence of financial reporting for reasons other than force majeure, change or failure of auditor or corporate restructuring (e.g. demerger).

Source: Fitch.

EXHIBIT EL-6
EXHIBIT EL-7
EXHIBIT EL-8
EXHIBIT EL-9
EXHIBIT EL-10
EXHIBIT EL-11
EXHIBIT EL-12

The information is confidential and will be made available only after execution of a certification to be bound by the draft protective order set forth in Section VII of this Rate Filing Package or a protective order issued in this docket.

2022 RATE CASE
ONCOR ELECTRIC DELIVERY COMPANY LLC
WORKPAPERS FOR
THE DIRECT TESTIMONY OF
ELLEN LAPSON

The information is confidential and will be made available only after execution to be bound by the draft protective order set forth in Section VII of this Rate Filing Package or a protective order issued in this docket.

Additionally, in accordance with RFP General Instruction No. 12(c), below is a list of the files that are being provided electronically:

Testimony Workpapers/Confidential/Lapson

WP – Lapson Direct _Confidential.xlxs

INDEX TO THE DIRECT TESTIMONY
OF DYLAN W. D'ASCENDIS, WITNESS FOR
ONCOR ELECTRIC DELIVERY COMPANY LLC

APPENDICES

EXHIBITS

DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT EMPLOYMENT POSITION.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, NJ 08054. I am employed by ScottMadden, Inc. as a Partner.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have offered expert testimony on behalf of investor-owned utilities in over 30 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, one American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are included in Appendix A.

Q. HAVE YOU EVER SUBMITTED TESTIMONY BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS ("COMMISSION")?

A. Yes. I have previously submitted testimony before the Commission in Docket Nos. 51415 and 51802.

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to present evidence on behalf of Oncor Electric Delivery Company LLC ("Oncor" or the "Company") and recommend a return on common equity ("ROE") for the Company's rate base. I also assess the Company's proposed capital structure ratios.

Q. WAS YOUR TESTIMONY, INCLUDING EXHIBITS, PREPARED BY YOU OR AT YOUR DIRECTION?

A. My direct testimony, including exhibits, were prepared by me or under my direction, supervision, or control and are, to the best of my knowledge and belief, true and correct.

III. SUMMARY

Q. WHAT IS YOUR RECOMMENDED ROE FOR ONCOR?

A. I recommend that the Commission authorize Oncor the opportunity to earn an ROE of 10.30% on its rate base within a reasonable range of 9.60% to 11.60%. The proposed ratemaking capital structure is sponsored by Company witnesses Mr. Kevin R. Fease and Ms. Ellen Lapson. The proposed ratemaking cost of debt is sponsored by Company witness Mr.

Fease. The overall rate of return is summarized on page 1 of Exhibit DWD-1 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	55.00%	4.39%	2.41%
Common Equity	45.00%	10.30%	4.64%
Total	100.00%		7.05%

Q. PLEASE SUMMARIZE THE BASIS FOR YOUR RECOMMENDED ROE.

A. My recommended ROE of 10.30% is summarized on page 2 of Exhibit DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Oncor. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the discounted cash flow model ("DCF model"), the risk premium model ("RPM"), and the capital asset pricing model ("CAPM"), to the market data of a "Utility Proxy Group" whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a "Non-Price Regulated Proxy Group", which is similar in total risk to the Utility Proxy Group. In order to remain conservative, however, I did not consider the ROE model results of the Non-Price Regulated Proxy

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1 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) *("Hope").*

2 *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922) *("Bluefield").*

Group in the determination of my recommended range. The results derived from each of the analyses are as follows:

Table 2: Summary of Common Equity Cost Rates

DCF Model	9.05%
RPM	10.84%
CAPM	12.15%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.60%
Indicated Range of Common Equity Cost Rates	9.60% – 11.60%
Recommended Cost of Common Equity	10.30%

As shown in Table 2, the indicated range of common equity cost rates applicable to the Utility Proxy Group and Oncor is between 9.60% and 11.60%.[3]

After determining the Utility Proxy Group ROE, one must conduct a relative risk analysis to determine whether additional adjustments to the Utility Proxy Group ROE is warranted to reflect the unique risk of the Company. My relative risk analyses show that the Company is comparable in risk to the Utility Proxy Group and no adjustments to the Utility Proxy Group ROE are necessary.[4] Given the Utility Proxy Group indicated range of ROEs from 9.60% to 11.60%, I recommend the Commission to approve a specific ROE of 10.30% for the Company's jurisdictional rate base.

Q. HOW IS THE REMAINDER OF YOUR DIRECT TESTIMONY ORGANIZED?

3 The indicated range is equal to 100 basis points above and below the midpoint of my DCF, RPM, and CAPM model results for the Utility Proxy Group.

4 As shown on Exhibit DWD-10, Oncor's estimated market capitalization falls into the second decile, which is the same decile that the Utility Proxy Group falls into. Additionally, Oncor's implied Moody's long-term issuer rating of Baa1 is equivalent to the Utility Proxy Group's average long-term issuer rating, as shown on page 5 of Exhibit DWD-4.

A. The remainder of my direct testimony is organized as follows:

- Section IV – Provides an observation of current capital markets;
- Section V – Provides a summary of financial theory and regulatory principles pertinent to the development of the cost of capital;
- Section VI – Provides a description of the Company and explains the selection of the Utility Proxy Group used to develop my ROE recommendation;
- Section VII – Discusses the reasonableness of the Company's proposed capital structure;
- Section VIII – Describes the analyses on which my ROE recommendation is based;
- Section IX – Summarizes the range of applicable ROEs and includes a discussion of potential adjustments for Company-specific factors;
- Section X – Explains additional considerations the Commission should weigh in evaluating the Company's relative risk; and
- Section XI – Presents my conclusions.

IV. CAPITAL MARKET OBSERVATIONS

Q. DOES YOUR RECOMMENDED ROE CONSIDER THE CURRENT CAPITAL MARKET ENVIRONMENT?

A. Yes, it does. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken.

Q. PLEASE SUMMARIZE THE CURRENT CAPITAL MARKET ENVIRONMENT.

A. Generally, the economy is currently in an "inflationary environment," as evidenced by increased levels of the Consumer Price Index ("CPI") and other inflationary measures. In response to the increasing levels of inflation, on March 16, 2022, the Federal Reserve ("Fed") raised the Fed Funds Rate from 0.00% – 0.25% to 0.25% – 0.50%. The Fed has also signaled the possibility of additional increases in the Fed Funds Rate, which is already priced into the market. Overall, the current market environment can be summarized as one with increasing inflation, and expectations that the Fed will implement additional increases in the Fed Funds Rate over a relatively short period of time in an attempt to limit inflation.

Q. HAS CPI RISEN RECENTLY?

A. Yes, it has. As shown on Chart 1, CPI has increased exponentially since the beginning of the pandemic and more recently has experienced year-over-year increases not seen since the early 1980s.[5]

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5 Source: Bureau of Labor Statistics, Series Title: All items in U.S. city average, all urban consumers, seasonally adjusted, Series ID: CUSR0000SA0 (https://data.bls.gov/timeseries/CUSR0000SA0?output_view=pct_1mth)

Chart 1: Consumer Price Index Change, 1978-Current[6]

Given the rise in CPI as shown in Chart 1, even if inflation were to moderate to a degree, it would still remain significantly elevated compared to the last several years.

Q. IS INFLATION SUPPOSED TO BE ELEVATED FROM HISTORICAL LEVELS MOVING FORWARD?

A. Yes, it is. The ten- and 30-year breakeven inflation rates[7] have steadily increased since August 27, 2020, when Fed Chairman Jerome H. Powell released a statement noting that the Federal Open Market Committee ("FOMC") will adopt an approach towards inflation that, "could be viewed as a flexible form of average inflation targeting," meaning that following periods in which inflation has run below 2.00%, "appropriate monetary policy will

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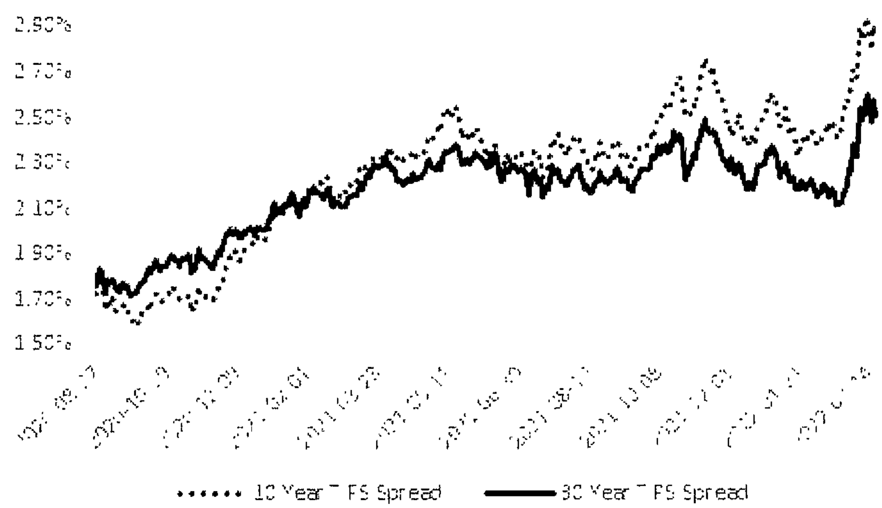
6 Source: Bureau of Labor Statistics, Series Title: All items in U.S. city average, all urban consumers, seasonally adjusted, Series ID: CUSR0000SA0 (https://data.bls.gov/timeseries/CUSR0000SA0?output_view=pct_1mth)

7 The breakeven inflation rate is the market's determination of the level of inflation during the period it measures. For example, the ten-year breakeven inflation rate is the market's expectation of inflation over the next ten years.

likely aim to achieve inflation moderately above 2 percent for some time."[8] More recently, Mr. Powell has noted that, "the risk is rising that an extended period of high inflation could push longer-term expectations uncomfortably higher, which underscores the need for the Committee to move expeditiously as I have described."[9]

In response to market conditions and Fed action, the breakeven inflation rate, represented as the ten-year and 30-year Treasury Inflation-Protected Securities spreads, has increased from 1.73% and 1.76% on August 27, 2020, respectively, to 2.86% and 2.51% respectively, as of March 18, 2022. Further, as shown in Chart 2 below, breakeven inflation has trended upward since the Fed's policy change at a relatively consistent pace.

Chart 2: Breakeven Inflation Since August 27, 2020[10]



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8 New Economic Challenges and the Fed's Monetary Policy Review, Remarks by Jerome H. Powell, Chair Board of Governors of the Federal Reserve System, August 27, 2020.

9 Restoring Price Stability, Chair Pro Tempore Jerome H. Powell, At "Policy Options for Sustainable and Inclusive Growth" 38th Annual Economic Policy Conference National Association for Business Economics, Washington, D.C., March 21, 2022.

10 Source: Federal Reserve (https://www.federalreserve.gov/datadownload/); downloaded on March 18, 2022.

Further, looking to other measures of inflation such as the Personal Consumption Expenditures Index, both with and without food and energy costs, recent quarterly increases are the highest they have been since the 1980s.[11]

Q. DID CHAIRMAN POWELL HAVE ANY ADDITIONAL COMMENTS CONCERNING INFLATION IN THE MARCH 21, 2022 SPEECH CITED ABOVE?

A. Yes, he did. In his speech at the 38th Annual Economic Policy Conference before the National Association for Business Economics, Chairman Powell stated:

> At the Federal Reserve, our monetary policy is guided by the dual mandate to promote maximum employment and stable prices. From that standpoint, the current picture is plain to see: The labor market is very strong, and inflation is much too high. My colleagues and I are acutely aware that high inflation imposes significant hardship, especially on those least able to meet the higher costs of essentials like food, housing, and transportation. There is an obvious need to move expeditiously to return the stance of monetary policy to a more neutral level, and then to move to more restrictive levels if that is what is required to restore price stability. We are committed to restoring price stability while preserving a strong labor market.
>
> At our meeting that concluded last week, we took several steps in pursuit of these goals: We raised our policy interest rate for the first time since the start of the pandemic and said that we anticipate that ongoing rate increases will be appropriate to reach our objectives. We also said that we expect to begin reducing the size of our balance sheet at a coming meeting. In my press conference, I noted that action could come as soon as our next meeting in May, though that is not a decision that we have made. These actions, along with the adjustments we have made since last fall, represent

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11 Bureau of Economic Analysis. Table 2.3.4. Price Indexes for Personal Consumption Expenditures by Major Type of Product (https://apps.bea.gov/iTable/iTable.cfm?reqid=19&step=2#reqid=19&step=2&isuri=1&1921=survey)

a substantial firming in the stance of policy with the intention of restoring price stability. In my comments today, I will first discuss the economic conditions that warrant these actions and then address the path ahead for monetary policy.

***

The rise in inflation has been much greater and more persistent than forecasters generally expected. For example, at the time of our June 2021 meeting, every Federal Open Market Committee (FOMC) participant and all but one of 35 submissions in the Survey of Professional Forecasters predicted that 2021 inflation would be below 4 percent. Inflation came in at 5.5 percent.[2][Footnote Omitted]

***

As the magnitude and persistence of the increase in inflation became increasingly clear over the second half of last year, and as the job market recovery accelerated beyond expectations, the FOMC pivoted to progressively less accommodative monetary policy. In June, the median FOMC participant projected that the federal funds rate would remain at its effective lower bound through the end of 2022, and as the news came in, the projected policy paths shifted higher (figure 5) [not included]. The median projection that accompanied last week's 25 basis point rate increase shows the federal funds rate at 1.9 percent by the end of this year and rising above its estimated longer-run normal value in 2023. The latest FOMC statement also indicates that the Committee expects to begin reducing the size of our balance sheet at a coming meeting. I believe that these policy actions and those to come will help bring inflation down near 2 percent over the next 3 years.

***

The ultimate responsibility for price stability rests with the Federal Reserve. Price stability is essential if we are going to have another sustained period of strong labor market conditions. I believe that the policy approach that I have laid out is well suited to achieving this outcome. We will take the necessary steps to ensure a return to price stability. In particular, if we conclude that it is appropriate to move more

> aggressively by raising the federal funds rate by more than 25 basis points at a meeting or meetings, we will do so. And if we determine that we need to tighten beyond common measures of neutral and into a more restrictive stance, we will do that as well.[12]

As can be gleaned by Chairman Powell's speech, he expects inflation to continue well into next year and that the Fed will continue to use the tools at their disposal to support the economy and the labor market, including accelerating the pace of rate increases of the Fed Funds Rate.

Q. IS THE MARKET CURRENTLY PRICING IN EXPECTATIONS OF SIGNIFICANT FUTURE FED FUNDS RATE INCREASES?

A. Yes. The CME FedWatch Tool, as presented in Chart 3 below, indicates that investors are pricing in at least six rate hikes by 2023, as based on an increase in the Fed Funds Rate from its current level of 0.25% – 0.50%, to 1.75% – 2.00% (assuming rate hikes in 25 basis point increments). Further approximately 86% of investors are pricing in at least eight rate hikes. Assuming 25 basis point incremental rate hikes, this translates into an expected increase in the Fed Funds Rate of at least 150 basis points (based on six rate hikes) to 200 basis points (based on eight rate hikes).

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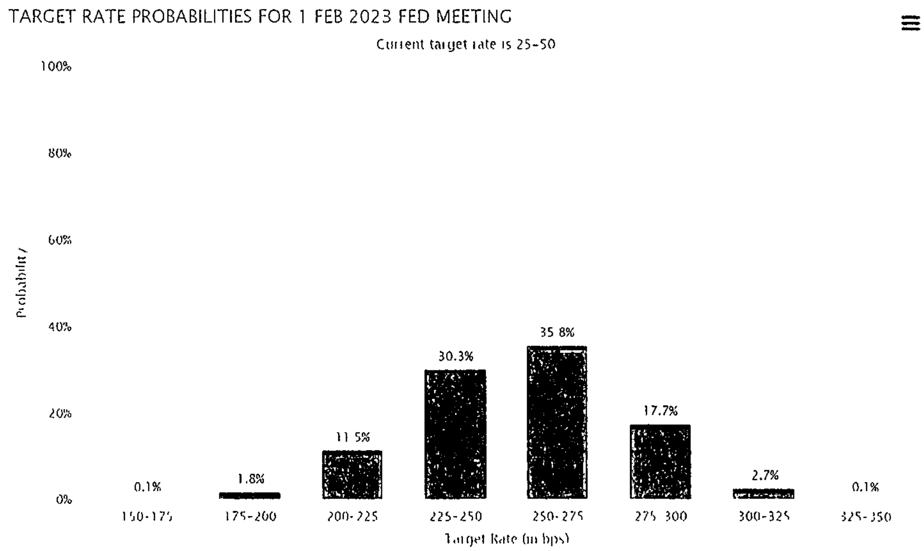
12 Restoring Price Stability, Chair Pro Tempore Jerome H. Powell, At "Policy Options for Sustainable and Inclusive Growth" 38th Annual Economic Policy Conference National Association for Business Economics, Washington, D.C., March 21, 2022.

Chart 3: CME FedWatch Tool – February 1, 2023 FOMC Meeting[13]



Q. PLEASE SUMMARIZE YOUR OBSERVATIONS OF THE CURRENT MARKET ENVIRONMENT.

A. In light of the current inflationary environment, the Fed recently raised the Fed Funds Rate and anticipates additional increases over the next year. Market participants have already priced in several rate increases as well. Regardless of current and future actions of the Fed, however, they have acknowledged that inflation is higher than its target average level of 2.00% and will continue to run higher than that target well into 2022 and possibly beyond. Increasing inflation drives all costs higher (*e.g.,* prices for materials, labor, capital). This is an economic reality that affects companies across the board and as discussed by the Company in the direct testimonies of Messrs. James A. Greer and Wesley R. Speed, Oncor is not immune to such increases. As a result, higher inflation may increase risk, and the investor-required return, for utility investors.

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13 Source: https://www.cmegroup.com/trading/interest-rates/countdown-to-fomc.html, accessed March 22, 2022.

V. GENERAL PRINCIPLES

Q. WHAT GENERAL PRINCIPLES HAVE YOU CONSIDERED IN ARRIVING AT YOUR RECOMMENDED COMMON EQUITY COST RATE OF 10.30%?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, *i.e.,* the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400,402. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the

> financial integrity of the enterprise, so as to maintain its credit and to attract capital.[14]

In summary, the U.S. Supreme Court has found a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. Therefore, the Commission's decision in this proceeding should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure their financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, *i.e.,* for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of the source of the funding, whether it be public funding or corporate funding.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other, similarly situated companies. In that regard, investors value corporate entities on a sum-of-

[14] *Hope*, 320 U.S. 591 (1944), at 603.

the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective, as measured by its combined business and financial risks. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (*i.e.*, business risk) and financing (*i.e.*, financial risk) of the Company on a stand-alone basis.

Q. WITHIN THAT BROAD FRAMEWORK, HOW IS THE COST OF CAPITAL ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (*i.e.*, rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values with appropriate adjustments.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

Q. IS THE AUTHORIZED RETURN SET IN REGULATORY PROCEEDINGS GUARANTEED?

A. No, it is not. Consistent with the *Hope* and *Bluefield* standards, the ratemaking process should provide the utility a reasonable opportunity to recover its return of, and return on, its reasonably incurred investments, but it does not guarantee that return. While a utility may have control over some factors that affect the ability to earn its authorized return (*e.g.*, management performance, operating and maintenance expenses, *etc.*), there are several factors beyond a utility's control that affect its ability to earn its authorized return. Those may include factors such as weather, the economy, and the prevalence and magnitude of regulatory lag. Company witness Mr. Fease has additional analysis in his direct testimony regarding factors that contribute to the Company not having a reasonable opportunity to earn its authorized return even if the Commission set the ROE at a reasonable level.

A. Business Risk

Q. PLEASE DEFINE BUSINESS RISK AND EXPLAIN WHY IT IS IMPORTANT FOR DETERMINING A FAIR RATE OF RETURN.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies including distributed energy resources, and the vagaries of weather.

Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. When determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (*i.e.,* the Utility Proxy Group). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. PLEASE DEFINE FINANCIAL RISK AND EXPLAIN WHY IT IS IMPORTANT IN DETERMINING A FAIR RATE OF RETURN.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (*i.e.*, failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. CAN BOND AND CREDIT RATINGS BE A PROXY FOR A FIRM'S COMBINED BUSINESS AND FINANCIAL RISKS TO EQUITY OWNERS (*I.E.*, INVESTMENT RISK)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (*i.e.*, total risk) faced by bond investors.[15] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

Q. DO RATING AGENCIES ACCOUNT FOR COMPANY SIZE IN THEIR BOND RATINGS?

A. No. Standard & Poor ("S&P"), Moody's Investor Services ("Moody's"), and FitchRatings ("Fitch") do not have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.

VI. ONCOR AND THE UTILITY PROXY GROUP

Q. ARE YOU FAMILIAR WITH ONCOR'S OPERATIONS?

A. Yes. Oncor provides electricity distribution and transmission delivery services to more than 3.8 million homes and business in Texas.[16] Oncor has long-term issuer ratings of A from S&P and an implied long-term issuer

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15 Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, *e.g.*, within the A category, an S&P rating can be an A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, *e.g.*, within the A category, a Moody's rating can be A1, A2, and A3.

16 *See,* Oncor Electric Delivery Company LLC, Annual Report on Form 10-K for the year ended December 31, 2021 filed with the SEC on February 25, 2022 ("SEC Form 10-K") at 6 (Dec. 31, 2021).

rating of Baa1 from Moody's,[17] and BBB+ by Fitch. Oncor is a majority-owned subsidiary of Oncor Electric Delivery Holdings Company LLC ("Oncor Holdings"), which is indirectly and wholly-owned by Sempra Energy ("Sempra"). In lieu of common stock, Oncor has membership interests that are not publicly-traded. Oncor Holdings owns 80.25% of Oncor's outstanding membership interests and Texas Transmission Investment LLC owns 19.75% of Oncor's outstanding membership interests.[18] Sempra's common stock is publicly traded under ticker symbol SRE.

Q. WHY IS IT NECESSARY TO DEVELOP A PROXY GROUP WHEN ESTIMATING THE ROE FOR THE COMPANY?

A. Because the Company does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[19]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly

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17 As noted by Company witness Ms. Lapson, Moody's policy is to rate senior secured mortgage bonds of utilities two notches higher than its undisclosed senior unsecured rating. Exhibit DWD-11 presents the rating notch difference between the long-term issuer and senior secured ratings for the Utility Proxy Group operating subsidiaries for which both long-term issuer and senior secured ratings are available, and confirms Moody's policy. Given Oncor's senior secured rating of A2, its implied long-term issuer rating would be Baa1.

18 *See,* Oncor Electric Delivery Company LLC, SEC Form 10-K at 6 (Dec. 31, 2021).

19 The development of the Non-Price Regulated Proxy Group is explained in more detail in Section VIII.

wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses that necessarily must consider the sort of quantitative and qualitative information discussed throughout my direct testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group indicated results.

My analyses are based on the Utility Proxy Group, which is comprised of U.S. electric utilities. As discussed earlier, utilities must compete for capital with other companies with commensurate risk (including non-utilities) and, to do so, must be provided the opportunity to earn a fair and reasonable return. Consequently, it is appropriate to consider the Utility Proxy Group's market data in determining the Company's ROE.

Q. PLEASE EXPLAIN HOW YOU CHOSE THE COMPANIES IN THE UTILITY PROXY GROUP.

A. The companies selected for the Utility Proxy Group met the following criteria:

(i) they were included in the Eastern, Central, or Western Electric Utility Group of *Value Line Investor Services ("Value Line")* (Standard Edition);

(ii) they have 70% or greater of fiscal year 2021 total operating income derived from, and 70% or greater of fiscal year 2021 total assets attributable to, regulated electric operations;

(iii) at the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (*i.e.,* one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) they have not cut or omitted their common dividends during the five years ended 2021 or through the time of preparation of this testimony;

(v) they have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted beta coefficients ("beta");

(vi) they have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

(vii) they have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.

The following 14 companies met these criteria:

Table 3: Utility Proxy Group Companies

Company Name	**Ticker Symbol**
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Duke Energy	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Eversource Energy	ES
IDACORP, Inc.	IDA
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Portland General Electric Co.	POR
The Southern Company	SO
Xcel Energy, Inc.	XEL

Q. PLEASE DESCRIBE EXHIBIT DWD-2, PAGE 2.

A. Page 2 of Exhibit DWD-2 contains comparative capitalization and financial statistics for the Utility Proxy Group for the years 2017 to 2021.

During the five-year period ending 2021, the historically achieved average earnings rate on book common equity for the group averaged 9.15% (after considering the effects of goodwill), the average common equity ratio based on total permanent capital (excluding short-term debt) was 45.01%, and the average dividend payout ratio was 75.40%.

Total debt to earnings before interest, taxes, depreciation, and amortization for the years 2017 to 2021 ranges between 4.55 and 6.07 times, with an average of 5.19 times. Funds from operations to total debt range from 9.76% to 17.91%, with an average of 13.91%.

VII. CAPITAL STRUCTURE

Q. WHAT IS ONCOR'S PROPOSED CAPITAL STRUCTURE?

A. Oncor's proposed capital structure consists of 55.00% long-term debt and 45.00% common equity, as testified to by Company witnesses Mr. Fease and Ms. Lapson.

Q. DOES ONCOR HAVE A SEPARATE CAPITAL STRUCTURE THAT IS RECOGNIZED BY INVESTORS?

A. Yes. Oncor is a separate corporate entity that has its own capital structure and issues its own debt.

Q. HOW DOES THE COMPANY'S PROPOSED COMMON EQUITY RATIO OF 45.00% COMPARE WITH THE COMMON EQUITY RATIOS MAINTAINED BY THE UTILITY PROXY GROUP?

A. As indicated by the analysis discussed below, the Company's proposed ratemaking common equity ratio of 45.00% is reasonable and consistent with the range of common equity ratios maintained by the Utility Proxy Group. As shown on pages 2 and 3 of Exhibit DWD-2, common equity ratios of the companies in the Utility Proxy Group range from 30.78% to 57.15% for fiscal year 2021.

I also considered *Value Line* projected capital structures for the utilities for 2024-2026. That analysis shows a range of projected common equity ratios between 33.00% and 53.00%.[20]

[20] *See*, pages 2 through 15 of Exhibit DWD-3.

In addition to comparing the Company's proposed common equity ratio with common equity ratios currently and expected to be maintained by the Utility Proxy Group, I also compared the Company's proposed common equity ratio with the equity ratios maintained by the operating utility subsidiaries of the Utility Proxy Group companies. As shown on page 4 of Exhibit DWD-2, common equity ratios of the operating utility subsidiaries of the Utility Proxy Group range from 40.96% to 58.26% for fiscal year 2021.

I have provided my observations with Company witnesses Mr. Fease and Ms. Lapson.

Q. IS ONCOR'S PROPOSED EQUITY RATIO OF 45.00% APPROPRIATE FOR RATEMAKING PURPOSES GIVEN THE RANGE OF THE UTILITY PROXY GROUP?

A. Yes, it is. In addition to the reasons set forth in the testimony of Company witnesses Mr. Fease and Ms. Lapson, the Company's proposed equity ratio of 45.00% is appropriate for ratemaking purposes in the current proceeding because it is within the range of the common equity ratios currently maintained and expected to be maintained, by the Utility Proxy Group and their operating subsidiaries.

VIII. COMMON EQUITY COST RATE MODELS

Q. IS IT IMPORTANT THAT COST OF COMMON EQUITY MODELS BE MARKET-BASED?

A. Yes. As discussed previously, regulated public utilities, like the Company, must compete for equity in capital markets along with all other companies with commensurate risk, including non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies with comparable risk, they will choose the company providing a higher return over a company providing a lower return.

Q. ARE THE COST OF COMMON EQUITY MODELS YOU USE MARKET-BASED MODELS?

A. Yes. The DCF model is market-based in that market prices are used in developing the dividend yield component of the model. The RPM and CAPM are also market-based in that the bond/issuer ratings and expected bond yields/risk-free rate used in the application of the RPM and CAPM reflect the market's assessment of bond/credit risk. In addition, the use of beta to determine the equity risk premium also reflects the market's assessment of market/systematic risk, as betas are derived from regression analyses of market prices. Moreover, market prices are used in the development of the monthly returns and equity risk premiums used in the Predictive Risk Premium Model ("PRPM"), one of the specific methods used in the RPM analysis. Selection criteria for the Non-Price Regulated Proxy Group are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. WHAT ANALYTICAL APPROACHES DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely focus on different aspects of return requirements and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while risk premium-based methods (*i.e.,* the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

The use of multiple models also makes intuitive sense when we consider that market prices are set by the buying and selling behavior of multiple investors, whose circumstances, objectives, and constraints vary over time and across market conditions. We cannot assume a single method is the best measure of the factors motivating those decisions for all investors at all times. Giving undue weight to a single method runs the very real risk of ignoring important information provided by other methods.

In other words, no single model is more reliable than all others under all market conditions. Intuition suggests it is more appropriate to use as many methods as we reasonably can and to reflect the many factors motivating investment decisions as best we can. In this instance, intuition, financial theory,[21] and financial practice reach a common conclusion: we should apply and reasonably consider multiple methods when estimating the ROE.

21 As Brigham explains: "Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate [the ROE]. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive – no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand." Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 7th ed., The Dryden Press, 1994, at 341.

A. Discounted Cash Flow Model

Q. WHAT IS THE THEORETICAL BASIS OF THE DCF MODEL?

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF model theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; *i.e.*, the total common equity return rate expected by investors.

Q. WHICH VERSION OF THE DCF MODEL DID YOU USE?

A. I used the single-stage constant growth DCF model in my analyses.

Q. PLEASE DESCRIBE THE DIVIDEND YIELD YOU USED IN APPLYING THE SINGLE STAGE CONSTANT GROWTH DCF MODEL.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of March 18, 2022, divided by the average closing market price for the 60 trading days ended March 18, 2022.[22]

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE DIVIDEND YIELD.

A. Because dividends are paid periodically (*e.g.*, quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the "Gordon Periodic," version of the DCF model.

DCF model theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the

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[22] *See,* Column 1, page 1 of Exhibit DWD-3.

dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Exhibit DWD-3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

Q. PLEASE EXPLAIN THE BASIS FOR THE GROWTH RATES YOU APPLY TO THE UTILITY PROXY GROUP IN YOUR CONSTANT GROWTH DCF MODEL.

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF model analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using projected earnings growth rates in a DCF model analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF model.

Q. PLEASE SUMMARIZE THE CONSTANT GROWTH DCF MODEL RESULTS.

A. As shown on page 1 of Exhibit DWD-3, for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 8.89%, the median result is 9.21%, and the average of the two is 9.05%. In arriving at a conclusion for the constant growth DCF model-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF model.

B. Risk Premium Model

Q. PLEASE DESCRIBE THE THEORETICAL BASIS OF THE RPM.

A. The RPM is based on the fundamental financial principle of risk and return, namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. PLEASE EXPLAIN HOW YOU DERIVED YOUR INDICATED COST OF COMMON EQUITY BASED ON THE RPM.

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the PRPM and the second method was a risk premium model using a total market approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

1. RPM Method 1 - PRPM

Q. PLEASE EXPLAIN THE PRPM.

A. The PRPM, published in the *Journal of Regulatory Economics,*[23] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility" or "ARCH."[24] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

A generalized form of the ARCH methodology ("GARCH") has been well tested by academia since Engle's, *et al.* research was originally published in 1982, 39 years ago. The PRPM is in the public domain, having been published six times in academically peer-reviewed journals: Journal of Economics and Business (June 2011 and April 2015),[25] The Journal of Regulatory Economics (December 2011),[26] The Electricity Journal (May

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[23] Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. *A New Approach for Estimating the Equity Risk Premium for Public Utilities*, The Journal of Regulatory Economics (December 2011), 40:261-278.

[24] Autoregressive conditional heteroscedasticity; *See also,* www.nobelprize.org.

[25] *See,* Eugene A. Pilotte, and Richard A. Michelfelder, *Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing*, Journal of Economics and Business, June 2011, 582-604. *See also,* Richard A. Michelfelder, *Empirical Analysis of the Generalized Consumption Asset Pricing Model: Estimating the Cost of Capital*, Journal of Economics and Business, April 2015, 37-50.

[26] *See,* Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, *New Approach to Estimating the Equity Risk Premium for Public Utilities*, The Journal of Regulatory Economics, December 2011, at 40:261-278.

2013 and March 2020),[27] and Energy Policy (April 2019).[28] Notably, none of these articles have been rebutted in the academic literature.

The PRPM is also cited in the following textbooks on cost of capital by authors unaffiliated with the authors of the academic articles cited above:

- Shannon Pratt and Roger Grabowski, Cost of Capital: Applications and Examples, (Fifth Edition), Wiley & Sons, 2015;
- Shannon Pratt and Roger Grabowski, The Lawyer's Guide to Cost of Capital: Understanding Risk and Return for Valuing Businesses and Other Investments, ABA Publishing, 2015; and
- Roger A. Morin, Modern Regulatory Finance, PUR Books, 2021.

Q. HOW DOES THE PRPM ESTIMATE THE INVESTOR-REQUIRED RETURN?

A. The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. I use the well-established GARCH methodology (noted above) to estimate the PRPM model using a standard commercial and relatively inexpensive statistical package, Eviews,©[29] to develop a means by which to estimate a predicted equity risk premium which, when added to a relevant bond yield, results in an indicated cost of common equity. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (*i.e.*, the variance of historical equity risk premiums).

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27 *See,* Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, *Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity,* The Electricity Journal, April 2013, at 84-89; *see also,* Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, *Decoupling, Risk Impacts and the Cost of Capital*, The Electricity Journal, January 2020.

28 *See,* Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, *Decoupling Impact and Public Utility Conservation Investment*, Energy Policy, April 2019, 311-319.

29 In addition to Eviews,® the GARCH methodology can be applied and the PRPM derived using other standard statistical software packages such as SAS, RATS, S-Plus and JMulti, which are not cost-prohibitive.

The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term U.S. Treasury securities through February 2022. Using the GARCH methodology, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software.

When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series[30] and a GARCH coefficient.[31] Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[32] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 2.89%[33] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from *Blue Chip Financial Forecasts ("Blue Chip").*[34] The mean PRPM indicated common equity cost rate for the Utility Proxy Group is 10.85%, the median is 10.69%, and the average of the two is 10.77%. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 10.77%.

2. RPM Method 2 – Total Market Approach

Q. PLEASE EXPLAIN THE TOTAL MARKET APPROACH RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium; (2) an equity risk premium based

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30 Illustrated on Columns 1 and 2, page 2 of Exhibit DWD-4.
31 Illustrated on Column 4, page 2 of Exhibit DWD-4.
32 Annualized Return = (1 + Monthly Return) ^12 – 1.
33 *See,* Column 6, page 2 of Exhibit DWD-4.
34 *See, Blue Chip Financial Forecasts*, March 1, 2022 at page 2 and December 1, 2021 at page 14.

on the *S&P Utilities Index*; and (3) an equity risk premium based on authorized ROEs for electric utilities.

Q. PLEASE EXPLAIN THE BASIS OF THE EXPECTED BOND YIELD OF 4.53% APPLICABLE TO THE UTILITY PROXY GROUP.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second calendar quarter of 2023, and *Blue Chip's* long-term projections for 2023 to 2027, and 2028 to 2032. As shown on line 1, page 3 of Exhibit DWD-4, the average expected yield on Moody's Aaa-rated corporate bonds is 3.95%. In order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield, I made an upward adjustment of 0.41%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[35] Adding that recent 0.41% spread to the expected Aaa-rated corporate bond yield of 3.95% results in an expected A2-rated public utility bond yield of 4.36%. Because the Utility Proxy Group's average Moody's long-term issuer rating is Baa1, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of 0.17%, which represents two-thirds of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the A2-rated prospective bond yield applicable to an Baa1-rated public utility bond.[36] Adding the 0.17% to the 4.36% prospective A2-rated public utility bond yield results in a 4.53% expected bond yield applicable to the Utility Proxy Group.

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35 As shown on line 2 and explained in note 2, page 3 of Exhibit DWD-4.

36 As shown on line 4 and explained in note 3, page 3 of Exhibit DWD-4.

Table 4: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[37]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)*	3.95%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.41%
Adjustment to Reflect the Utility Proxy Group's Average Moody's Bond Rating of Baa1	0.17%
Prospective Bond Yield Applicable to the Utility Proxy Group	4.53%

Q. PLEASE EXPLAIN HOW THE BETA-DERIVED EQUITY RISK PREMIUM IS DETERMINED.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds; and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 9, on page 8 of Exhibit DWD-4. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums, and a Bloomberg-based equity risk premium. Each of these is described below.

Q. HOW DID YOU DERIVE A MARKET EQUITY RISK PREMIUM BASED ON LONG-TERM HISTORICAL DATA?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the *Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2021 ("SBBI-2021")*[38] less the average historical yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2020. Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment

37 As shown on page 3 of Exhibit DWD-4.

38 *See, SBBI-2021* Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2020.

horizon presumed by investing in a going concern, *i.e.*, a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 11.94% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 6.02%.[39] As shown on line 1, page 8 of Exhibit DWD-4, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.92%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa-rated corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in *SBBI-2021*.[40] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. PLEASE EXPLAIN THE DERIVATION OF THE REGRESSION-BASED MARKET EQUITY RISK PREMIUM.

A. To derive the regression-based market equity risk premium of 8.23% shown on line 2, page 8 of Exhibit DWD-4, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market

39 As explained in note 1, page 9 of Exhibit DWD-4.
40 *See, SBBI-2021*, at page 10-22.

equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

Q. PLEASE EXPLAIN THE DERIVATION OF THE PRPM EQUITY RISK PREMIUM.

A. I used the same PRPM approach described above for the PRPM equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through February 2022.[41] Using the previously discussed GARCH, the projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 8.07%.[42]

Q. PLEASE EXPLAIN THE DERIVATION OF A PROJECTED EQUITY RISK PREMIUM BASED ON *VALUE LINE* DATA FOR YOUR RPM ANALYSIS.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 9 of Exhibit DWD-4. Consistent with my calculation of the dividend yield component in my DCF model analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended March 18, 2022, plus an average of the median estimated

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41 Data from January 1928 to December 2020 is from *SBBI-2021*. Data from January 2021 to February 2022 is from Bloomberg.

42 Shown on line 3, page 8 of Exhibit DWD-4.

dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (Standard Edition).[43]

The average median expected price appreciation is 44%, which translates to a 9.54% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 1.85%, equates to a forecasted annual total return rate on the market of 11.39%. The forecasted Moody's Aaa-rated corporate bond yield of 3.95% is deducted from the total market return of 11.39%, resulting in an equity risk premium of 7.44%, as shown on line 4, page 8 of Exhibit DWD-4.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON THE S&P 500 COMPANIES.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 16.14%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.95% results in an 12.19% projected equity risk premium.

Q. PLEASE EXPLAIN THE DERIVATION OF AN EQUITY RISK PREMIUM BASED ON BLOOMBERG DATA.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 14.60%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 3.95% results in a 10.65% projected equity risk premium.

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43 As explained in detail in note 1, page 2 of Exhibit DWD-5.

Q. WHAT IS YOUR CONCLUSION OF A BETA-DERIVED EQUITY RISK PREMIUM FOR USE IN YOUR RPM ANALYSIS?

A. I gave equal weight to all six equity risk premiums based on each source – historical, *Value Line*, and Bloomberg – in arriving at an 8.75% equity risk premium (*see* Table 5, below).

Table 5: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[44]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2020)	5.92%
Regression Analysis on Historical Data	8.23%
PRPM Analysis on Historical Data	8.07%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	7.44%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields	12.19%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	10.65%
Average	8.75%

After calculating the average market equity risk premium of 8.75%, I adjusted it by the beta to account for the risk of the Utility Proxy Group. As discussed below, the beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Exhibit DWD-5, the average of the mean and median beta for the Utility Proxy Group is 0.93. Multiplying

44 As shown on page 8 of Exhibit DWD-4.

the 0.93 average beta by the market equity risk premium of 8.75% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 8.14%.

Q. HOW DID YOU DERIVE THE EQUITY RISK PREMIUM BASED ON THE S&P UTILITY INDEX AND MOODY'S A-RATED PUBLIC UTILITY BONDS?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the *S&P Utilities Index*, using *Value Line* and Bloomberg data, respectively. Turning first to the *S&P Utilities Index* holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the *S&P Utilities Index* total returns of 10.65% and monthly Moody's A2-rated public utility bond yields of 6.49% from 1928 to 2020, to arrive at an equity risk premium of 4.16%.[45] I then used the same historical data to derive an equity risk premium of 6.04% based on a regression of the monthly equity risk premiums. The final *S&P Utilities Index* holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to February 2022 to arrive at a PRPM-derived equity risk premium of 5.27% for the *S&P Utilities Index.*

I then derived expected total returns on the *S&P Utilities Index* of 10.69% and 9.78% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 4.36%[46], which resulted in equity risk premiums of 6.33% and 5.42%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source (*i.e.*, historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 5.44%.

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45 As shown on line 1, page 12 of Exhibit DWD-4.

46 Derived on line 3, page 3 of Exhibit DWD-4.

Table 6: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[47]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2020)	4.16%
Regression Analysis on Historical Data	6.04%
PRPM Analysis on Historical Data	5.27%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields	6.33%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	5.42%
Average	5.44%

Q. HOW DID YOU DERIVE AN EQUITY RISK PREMIUM OF 5.52% BASED ON AUTHORIZED ROES FOR ELECTRIC UTILITIES?

A. The equity risk premium of 5.52% shown on line 3, page 7 of Exhibit DWD-4 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 13 of Exhibit DWD-4. Page 13 of Exhibit DWD-4 contains the graphical results of a regression analysis of 1,192 rate cases for electric utilities that were fully litigated during the period from January 1, 1980, through March 18, 2022. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial

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47 As shown on page 12 of Exhibit DWD-4.

literature on the subject.[48] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 4.36%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 5.52%, which is shown on line 3, page 7 of Exhibit DWD-4.

Q. WHAT IS YOUR CONCLUSION OF AN EQUITY RISK PREMIUM FOR USE IN YOUR TOTAL MARKET APPROACH RPM ANALYSIS?

A. The equity risk premium I applied to the Utility Proxy Group is 6.37%, which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 8.14%, 5.44%, and 5.52%, respectively.[49]

Q. WHAT IS THE INDICATED RPM COMMON EQUITY COST RATE BASED ON THE TOTAL MARKET APPROACH?

A. As shown on line 7, page 3 of Exhibit DWD-4 and shown on Table 7, below, I calculated a common equity cost rate of 10.90% for the Utility Proxy Group based on the total market approach RPM.

Table 7: Summary of the Total Market Return Risk Premium Model[50]

Prospective Moody's Baa1 -Rated Utility Bond Applicable to the Utility Proxy Group	4.53%
Prospective Equity Risk Premium	6.37%
Indicated Cost of Common Equity	10.90%

48 *See, e.g.*, Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at pp. 33-45.

49 As shown on page 7 of Exhibit DWD-4.

50 As shown on page 3 of Exhibit DWD-4.

3. RPM Results

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE PRPM AND THE TOTAL MARKET APPROACH RPM?

A. As shown on page 1 of Exhibit DWD-4, the indicated RPM-derived common equity cost rate is 10.84%, which gives equal weight to the PRPM (10.77%) and the adjusted-market approach results (10.90%).

C. Capital Asset Pricing Model

Q. PLEASE EXPLAIN THE THEORETICAL BASIS OF THE CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by the beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:

R_s = Return rate on the common stock;

R_f = Risk-free rate of return;

R_m = Return rate on the market as a whole; and

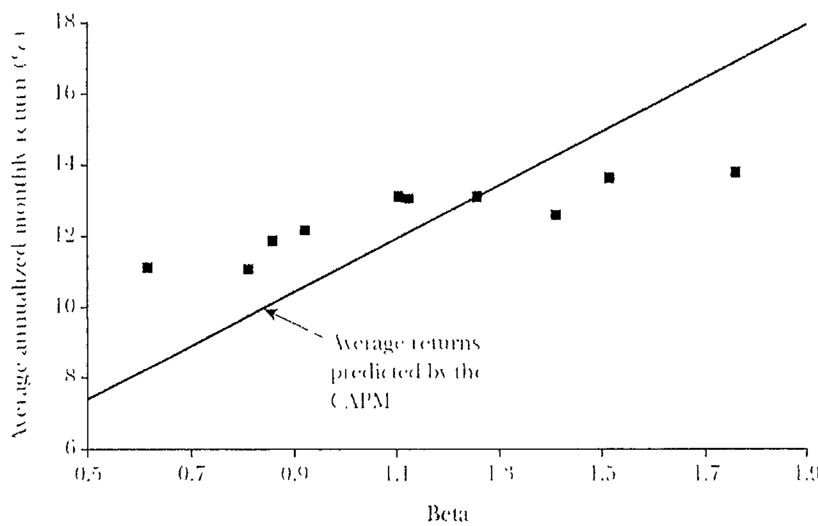
β = Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[51]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding their Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[52]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



Morin also states that:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM

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51 Roger A. Morin, Modern Regulatory Finance, at page 206 ("Morin").

52 Eugene F. Fama and Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004 at p. 33 ("Fama & French").

would predict, and high-beta securities earn less than predicted.[53]

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Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = R_F + x\,(R_M - R_F) + (1-x)\ \beta(R_M - R_F)$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)^{54}$$

Fama and French provide similar support for the ECAPM when they state:

The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too "flat."… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[55]

Finally, Fama and French further note:

Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the

53 Morin, at p. 207.
54 Morin, at p. 221.
55 Fama & French, at 32.

portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[56]

Clearly, the justification from Morin, and Fama and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. WHAT BETAS DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the betas in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg Professional Services. While both of those services adjust their calculated (or "raw") betas to reflect the tendency of the beta to regress to the market mean of 1.00, *Value Line* calculates the beta over a five-year period, while Bloomberg calculates it over a two-year period.

Q. PLEASE DESCRIBE YOUR SELECTION OF A RISK-FREE RATE OF RETURN.

A. As shown in Column 5, page 1 of Exhibit DWD-5, the risk-free rate adopted for both applications of the CAPM is 2.89%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2023, and long-term projections for the years 2023 to 2027 and 2028 to 2032.

Q. WHY IS THE YIELD ON LONG-TERM U.S. TREASURY BONDS APPROPRIATE FOR USE AS THE RISK-FREE RATE?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (*i.e.*,

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56 Fama & French, at 33.

cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. PLEASE EXPLAIN THE ESTIMATION OF THE EXPECTED RISK PREMIUM FOR THE MARKET USED IN YOUR CAPM ANALYSES.

A. The basis of the market risk premium is explained in detail in note 1 on page 2 of Exhibit DWD-5. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.05% was deducted from the *SBBI-2021* monthly historical total market return of 12.20%, which results in an historical market equity risk premium of 7.15%.[57] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from *SBBI-2021*. That regression analysis yielded a market equity risk premium of 9.38%. The PRPM market equity risk premium is 9.03% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through February 2022.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 2.89%, discussed above, from the *Value Line* projected total annual market return of 11.39%, resulting in a forecasted total market equity risk premium of 8.50%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 2.89% from the projected total return of the S&P 500 of 16.14%. The resulting market equity risk premium is 13.25%.

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[57] *SBBI-2021*, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 2.89% from the projected total return of the S&P 500 of 14.60%. The resulting market equity risk premium is 11.71%. These six measures, when averaged, result in an average total market equity risk premium of 9.84%.

Table 8: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[58]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2020)	7.15%
Regression Analysis on Historical Data	9.38%
PRPM Analysis on Historical Data	9.03%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	8.50%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields	13.25%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	11.71%
Average	9.84%

Q. WHAT ARE THE RESULTS OF YOUR APPLICATION OF THE TRADITIONAL AND EMPIRICAL CAPM TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Exhibit DWD-5, the mean result of my CAPM/ECAPM analyses is 12.16%, the median is 12.13%, and the average of the two is 12.15%. Consistent with my reliance on the average of mean

[58] As shown on page 2 of Exhibit DWD-5.

and median DCF model results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 12.15%.

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF Model, RPM, and CAPM

Q. WHY DO YOU ALSO CONSIDER A PROXY GROUP OF DOMESTIC, NON-PRICE REGULATED COMPANIES?

A. In the *Hope* and *Bluefield* cases, the U.S. Supreme Court did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group that is comparable in total risk to the Utility Proxy Group, because all of these companies compete for capital in the exact same markets.

Q. HOW DID YOU SELECT NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the beta and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (*i.e.*, five years). These selection criteria resulted in a proxy group of 48 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was as follows:

(i) they must be covered by *Value Line* (Standard Edition);

(ii) they must be domestic, non-price regulated companies, *i.e.*, not utilities;

(iii) their beta must lie within plus or minus two standard deviations of the average unadjusted beta of the Utility Proxy Group; and

(iv) the residual standard errors of the *Value Line* regressions that gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS THE DATA FROM WHICH YOU SELECTED THE 48 DOMESTIC, NON-PRICE REGULATED COMPANIES THAT ARE COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown on Exhibit DWD-6.

Q. IS THE USE OF UNADJUSTED BETAS AND STANDARD ERRORS OF THE REGRESSION SUPPORTED BY ACADEMIC AND FINANCIAL LITERATURE?

A. Yes, it is. Business and financial risks may vary between companies and proxy groups, but if the collective average betas and standard errors of the regression of the group are similar, then the total, or aggregate, non-diversifiable market risks and diversifiable risks are similar, as noted in "Comparable Earnings: New Life for an Old Precept" provided in Exhibit DWD-7. Thus, because the non-price regulated companies are selected based on analyses of market data, they are comparable in total risk (even though individual risks may vary) to the Utility Proxy Group. This is demonstrated clearly on page 273 of Jack C. Francis' Investments: Analysis and Management (page 3 of Exhibit DWD-8), which shows that total risk can be "partitioned into its systematic and unsystematic components." Essentially, companies that have similar betas and standard errors of regression have similar total investment risk.

Q. HAVE YOU PREPARED AN ADDITIONAL ANALYSIS TO DETERMINE WHETHER YOUR UTILITY PROXY GROUP AND NON-PRICE REGULATED PROXY GROUP ARE OF COMPARABLE RISK?

A. Yes, I have. I compared the average and median *Value Line* Safety Ranking[59] for the Utility Proxy Group and Non-Price Regulated Proxy Group, as shown on Table 9, below:

Table 9: Comparison of Safety Rankings of Mr. D'Ascendis' Utility Proxy Group and Non-Price Regulated Proxy Group

Group	Average Safety Ranking	Median Safety Ranking
Utility Proxy Group	1.71	2.00
Non-Price Regulated Proxy Group	1.75	2.00

As noted above, the Safety Rankings of the Utility Proxy Group and the Non-Price Regulated Proxy Group are comparable, indicating comparable total risk. This, in addition to all of the above, should lead the

59 *Value Line* also ranks stocks for Safety by analyzing the total risk of a stock compared to the approximately 1,700 stocks in the *Value Line* universe. Each of the stocks tracked in the *Value Line Investment Survey* is ranked in relationship to each other, from 1 (the highest rank) to 5 (the lowest rank). Safety is a quality rank, not a performance rank, and stocks ranked 1 and 2 are most suitable for conservative investors; those ranked 4 and 5 will be more volatile. Volatility means prices can move dramatically and often unpredictably, either down or up. The major influences on a stock's Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

Commission to consider the results of my Non-Price Regulated Proxy Group in its determination of Oncor's ROE in this proceeding.

Q. DID YOU CALCULATE COMMON EQUITY COST RATES USING THE DCF MODEL, RPM, AND CAPM FOR THE NON-PRICE REGULATED PROXY GROUP?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Exhibit DWD-9 derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF model for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 12.70%.

Pages 3 through 5 of Exhibit DWD-9 contain the data and calculations that support the 12.73% RPM common equity cost rate. As shown on line 1, page 3 of Exhibit DWD-9, the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the second quarter of 2023, and for the years 2023 to 2027 and 2028 to 2032, is 4.71%.[60] Because the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of Baa1, a downward adjustment of 0.12% to the projected Baa2-rated corporate bond yield is necessary to reflect a difference in ratings, which results in a projected Baa1 corporate bond yield of 4.59%.

When the beta-adjusted risk premium of 8.14%[61] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa1-rated

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60 *Blue Chip Financial Forecasts*, March 1, 2022, at page 2 and December 1, 2021, at page 14.

61 Derived on page 5 of Exhibit DWD-9.

corporate bond yield of 4.59%, the indicated RPM common equity cost rate is 12.73%.

Page 6 of Exhibit DWD-9 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 12.07% for the Non-Price Regulated Proxy Group.

Q. WHAT IS THE COST RATE OF COMMON EQUITY BASED ON THE NON-PRICE REGULATED PROXY GROUP COMPARABLE IN TOTAL RISK TO THE UTILITY PROXY GROUP?

A. As shown on page 1 of Exhibit DWD-9, the results of the common equity models applied to the Non-Price Regulated Proxy Group – which is comparable in total risk to the Utility Proxy Group – are as follows: 12.70% (DCF Model); 12.73% (RPM); and 12.07% (CAPM). The average of the mean and median of these models is 12.60%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group. To be conservative, I do not consider the results of this analysis in my determination of the reasonable range of ROEs attributable to the Utility Proxy Group.

IX. <u>CONCLUSION OF COMMON EQUITY COST RATE</u>

Q. WHAT IS THE RANGE OF INDICATED COMMON EQUITY COST RATES APPLICABLE TO YOUR UTILITY PROXY GROUP?

A. By applying multiple cost of common equity models to the Utility Proxy Group, the indicated range of common equity cost rates attributable to the Utility Proxy Group before any relative risk adjustments is between 9.60% and 11.60%. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

Based on these common equity cost results, I conclude that a range of common equity cost rates between 9.60% and 11.60% is reasonable. The indicated range was calculated by adding 100 basis points above and below the midpoint of my DCF, RPM, and CAPM results.

After a proxy group-specific ROE is determined, one must conduct a relative risk analysis to determine whether additional adjustments need to be made to reflect the unique risk of the subject company. Those analyses associated with relative size and credit risk show that Oncor and the Utility Proxy Group are indeed comparable in risk and no adjustments to the Utility Proxy Group ROE are necessary in this case.[62]

X. OTHER CONSIDERATIONS

Q. SHOULD THE COMMISSION CONSIDER THE COMPANY'S CUSTOMER GROWTH AND CORRESPONDING LEVEL OF CAPITAL EXPENDITURES?

A. Yes. As noted by Oncor, "[i]n recent years, Texas has seen increasing population and business growth, and we have experienced an increase in electricity consumption as a result."[63] Specifically, the Company notes that it has experienced an average growth of 2.27% per year for the last five years in the number of distribution system points.[64] Because of increased customer growth, and other factors, the Company must heavily invest in capital improvements to safely and reliably serve new (and existing) customers.

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62 As shown on Exhibit DWD-10, Oncor's estimated market capitalization falls into the second decile, which is the same decile that the Utility Proxy Group falls into. Additionally, Oncor's implied Moody's long-term issuer rating of Baa1 is equivalent to the Utility Proxy Group's average long-term issuer rating, as shown on page 5 of Exhibit DWD-4.

63 Oncor SEC Form 10-K for the Fiscal Year Ended December 31, 2021, at 28.

64 Oncor SEC Form 10-K for the Fiscal Year Ended December 31, 2021, at 28.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S CAPITAL INVESTMENT PLANS.

A. Oncor currently plans to invest approximately $12.05 billion of additional capital over the 2022-2025 period,[65] which represents approximately 52.5% of its 2021 net utility plant.[66] That amount includes investments required to support growth, and to maintain safe, sufficient, and reliable service in both its transmission and distribution facilities. As discussed by Company witnesses Messrs. E. Allen Nye, Greer and Fease, the Company will require continued access to the capital markets, at reasonable terms, to finance its capital spending plan. As the Company moves forward with its capital spending plan, timely recovery of its capital costs is critical to mitigate the delay of capital recovery and execute its capital spending program. Company witness Mr. Fease provides additional analysis of Oncor's ability to earn its authorized return during a period of high capital investment in his direct testimony.

Q. DO SUBSTANTIAL CAPITAL EXPENDITURES DIRECTLY RELATE TO A UTILITY BEING ALLOWED THE OPPORTUNITY TO EARN A RETURN ADEQUATE TO ATTRACT CAPITAL AT REASONABLE TERMS?

A. Yes, they do. The allowed ROE should enable the subject utility to finance capital expenditures and working capital requirements at reasonable rates and to maintain its financial integrity in a variety of economic and capital market conditions. As discussed throughout my direct testimony, a return adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness. To the extent a utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders should be disadvantaged.

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65 Oncor SEC Form 10-K for the Fiscal Year Ended December 31, 2021, at 38. The five-year plan (2022 - 2026) is $15 billion, which is also the largest capital plan announced for any utility in Texas.

66 Source: Oncor SEC Form 10-K for the Fiscal Year Ended December 31, 2021, at 51.

These requirements are of particular importance to a utility when it is engaged in a substantial capital expenditure program.

The ratemaking process is predicated on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of the utility and its ratepayers.

Further, the financial community carefully monitors the current and expected financial conditions of utility companies, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk. That is especially important during periods in which the utility expects to make significant capital investments and, therefore, may require access to capital markets.

Q. DO CREDIT RATING AGENCIES RECOGNIZE RISK ASSOCIATED WITH INCREASED CAPITAL EXPENDITURES?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. S&P has noted several long-term challenges for utilities' financial health including: heavy construction programs to address energy transformation, safety, and reliability; environmental, social, and governance concerns; and regulatory responsiveness to mounting requests for rate increases.[67] Specifically, S&P notes:

[67] S&P Global Ratings, Industry Top Trends 2022: North American Regulated Utilities, January 26, 2022, at 1.

> Over the past few years, the industry's financial measures have weakened. This reflects rising capital spending, regulatory lag, and lower authorized returns on equity...More recently, energy transformation has **increased capital spending, further weakening the industry's financial measures, pressuring credit quality**. We expect that energy transformation will take more than a decade to complete, likely continuing to pressure the industry's credit quality over this timeframe.[68]

The rating agency views noted above also are consistent with certain observations discussed in my direct testimony: (1) the benefits of maintaining a strong financial profile are significant when capital access is required and become particularly acute during periods of market instability; and (2) the Commission's decision in this proceeding will have a direct bearing on the Company's credit profile and its ability to access the capital needed to fund its investments.

Q. DOES INCREASING INFLATION INCREASE RISK AS IT PERTAINS TO THE COMPANY'S CAPITAL EXPENDITURE PLAN?

A. Yes. Increasing inflation increases risk for the Company in two ways: (1) the costs to make capital expenditures (*e.g.*, raw materials, labor) will increase, leading the Company to go to the market to raise larger amounts of capital as it would otherwise do in a non-inflationary environment; and (2) as inflation is positively correlated to capital costs, the financing of the increased costs will be more expensive than it would be in a non-inflationary environment. Inflation also directly affects operating costs as discussed in the direct testimony of Oncor witnesses Messrs. Nye, Greer and Speed, which also introduces additional risk.

Q. HOW DO THE COMPANY'S EXPECTED CAPITAL EXPENDITURES COMPARE TO THE UTILITY PROXY GROUP?

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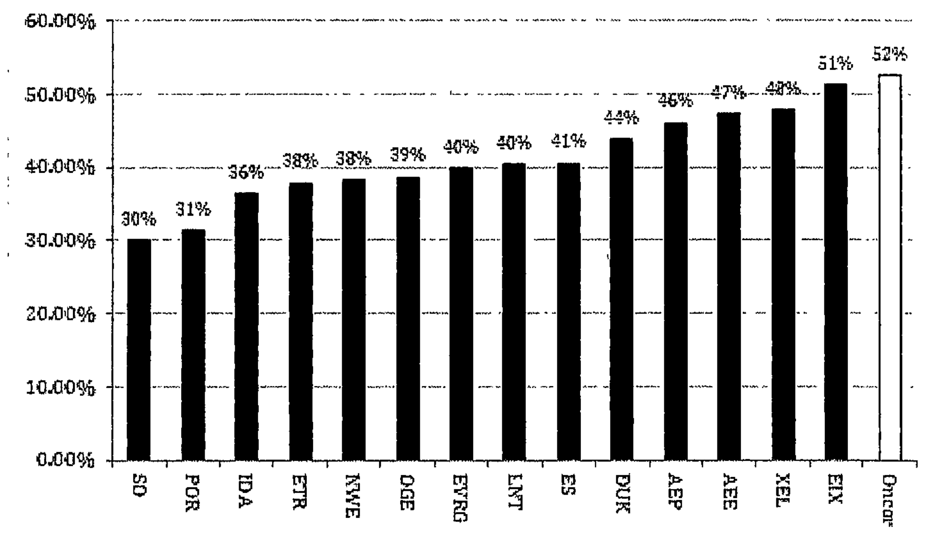
68 S&P Global Ratings, Industry Top Trends 2022: North American Regulated Utilities, January 26, 2022, at 6. (emphasis added)

A. To reasonably make that comparison, I calculated the ratio of expected capital expenditures to net plant for each company in the Utility Proxy Group. I performed that calculation using Oncor's projected capital expenditures during 2022 through 2025 relative to its net plant for the year ended December 31, 2021. As shown in Exhibit DWD-12, Oncor has the highest ratio of projected capital expenditures to net plant relative to the Utility Proxy Group, approximately 30.83% higher than the Utility Proxy Group median.

Chart 4: Capital Expenditures to Net Plant[69]



XI. CONCLUSIONS

Q. WHAT IS YOUR RECOMMENDED ROE FOR ONCOR?

A. Given the discussion above and the results from the analyses, I recommend that an ROE of 10.30% is appropriate for the Company at this time within a Company-specific indicated range of common equity cost rates between 9.60% and 11.60%. Further, the Commission should consider the Company's exceptional operating and management performance as

69 Source: Value Line, Oncor SEC Form 10-K for the Fiscal Year Ended December 31, 2021, at 38, 51.

discussed by Company witnesses Messrs. Nye, Greer, Fease, and other Company witnesses in determining the appropriate ROE for Oncor.

Q. IN YOUR OPINION, IS YOUR PROPOSED ROE OF 10.30% FAIR AND REASONABLE TO ONCOR AND ITS CUSTOMERS?

A. Yes, it is.

Q. IN YOUR OPINION, IS ONCOR'S PROPOSED CAPITAL STRUCTURE CONSISTING OF 55.00% LONG-TERM DEBT AND 45.00% COMMON EQUITY FAIR AND REASONABLE?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

AFFIDAVIT

STATE OF NEW JERSEY §
§
COUNTY OF BURLINGTON §

BEFORE ME, the undersigned authority, on this day personally appeared Dylan W. D'Ascendis, who, having been placed under oath by me, did depose as follows:

My name is Dylan W. D'Ascendis. I am of legal age and a resident of the State of New Jersey. The foregoing direct testimony and attached exhibits offered by me is true and correct, and the opinions stated therein are, to the best of my knowledge and belief, accurate, true and correct.

Dylan W. D'Ascendis

SUBSCRIBED AND SWORN TO BEFORE ME by the said Dylan W. D'Ascendis this 13th day of April, 2022.

Heather N. Fulmer
Notary Public, State of New Jersey

HEATHER N. FULMER
NOTARY PUBLIC OF NEW JERSEY
Commission # 50115526
My Commission Expires 10/25/2024

scottmadden
MANAGEMENT CONSULTANTS

Appendix A - Resume & Testimony Listing of:

Dylan W. D'Ascendis, CRRA, CVA
Partner

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and has become a leading expert witness with respect to cost of capital and capital structure. He has served as a consultant for investor-owned and municipal utilities and authorities for 13 years. Dylan has testified as an expert witness on over 100 occasions regarding rate of return, cost of service, rate design, and valuation before more than 30 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Regulation and Rates
- Rate of Return
- Valuation
- Mutual Fund Benchmarking
- Capital Market Risk
- Regulatory Strategy
- Cost of Service

Recent Expert Testimony Submission/Appearance

- Regulatory Commission of Alaska – Capital Structure
- Federal Energy Regulatory Commission – Rate of Return
- Public Utility Commission of Texas – Return on Equity
- Hawaii Public Utilities Commission – Cost of Service / Rate Design
- Pennsylvania Public Utility Commission - Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Articles and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
Colorado Public Utilities Commission				
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Delaware Public Service Commission				
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System	09/20	Peoples Gas System	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design

Sponsor	Date	Case/Applicant	Docket No.	Subject
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy	07/19	Atmos Energy	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy	04/20	Atmos Energy	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	Docket No. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure

Sponsor	Date	Case/Applicant	Docket No.	Subject
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
Southwestern Public Service Company	01/21	Southwestern Public Service Company	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Company	02/21	Southwestern Public Service Company	Docket No. 51802	Return on Equity
Southwestern Electric Power Company	10/20	Southwestern Electric Power Company	Docket No. 51415	Rate of Return
Virginia State Corporation Commission				
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
Monongahela Power Company and The Potomac Edison Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
Monongahela Power Company and The Potomac Edison Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity