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June 21, 2021

VIA ELECTRONIC FILING
Adam Teitzman, Commission Clerk
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

RE: Docket No. 20210015-EI
Petition by FPL for Base Rate Increase and Rate Unification

Dear Mr. Teitzman:

Attached for filing on behalf of Floridians Against Increased Rates, Inc. ("FAIR") in the above-referenced docket is Exhibit BTM-8.2 Part 2 to the Direct Testimony of FAIR witness Breandan Mac Mathuna.

Please let me know if you should have any questions regarding this submission.

Cordially yours,

Robert Scheffel Wright

Robert Scheffel Wright

RSW:mae
Encl.

S&P Global
Market Intelligence

June 15, 2020
spglobal.com/marketintelligence

RRA Regulatory Focus
The rate case process: a conduit to enlightenment

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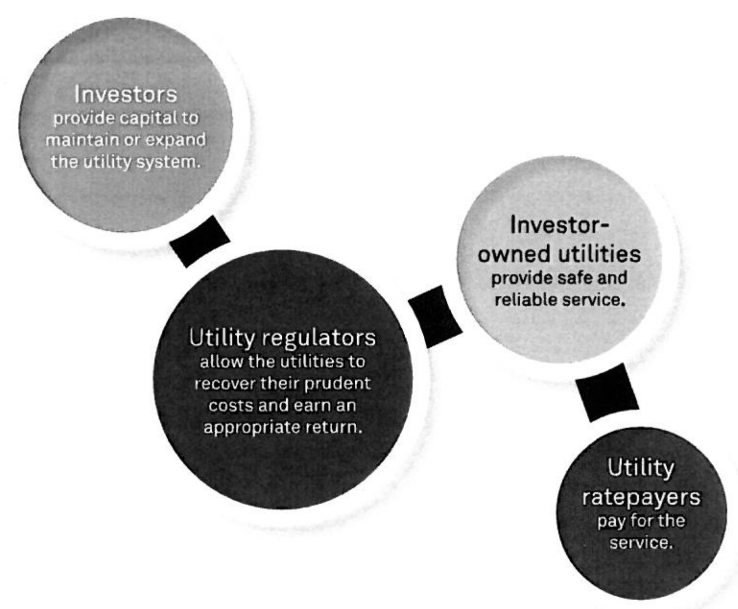
The utility sector is unlike any other sector of the economy. In a competitive industry, customers have numerous purchasing options. In the automotive or consumer products industry, customers can select from the product offerings of many different providers, and product quality and price have considerable influence on consumer purchasing decisions. If a seller's prices are too high or the quality of the product does not meet the customer's standards, the customer can select the wares offered by another seller. Prices in competitive industries are set by supply and demand in the marketplace.

Utilities, on the other hand, cannot simply set up shop wherever they choose. Utilities are natural monopolies because their capital costs are enormous. Monopolies, by definition, also have high barriers to entry. However, a company with monopoly power cannot be allowed to operate without oversight, otherwise the price of the company's product could be exorbitant. Hence, the state utility commissions were created to regulate the rates charged by the utilities and, together with the utilities themselves, investors and customers, comprise what is known as the "regulatory compact."

The regulatory compact is an agreement that is unique to the utility space and calls for the utility to provide safe, reliable and reasonably priced service, the commission to provide the utility with a reasonable opportunity to recover its costs and earn a return similar to that of other investments with similar risk characteristics, the customer to pay the approved rates and the investor to supply the capital necessary to maintain or expand the utility system.

The rate setting process is grounded in the fact that utilities operate as monopolies where, in the absence of regulation, there is no market for competitive pricing of the utility's product. This applies to utilities in non-restructured jurisdictions, whereas in restructured jurisdictions the power commodity itself can be considered competitively priced given the presence of competition for generation supply.

Regulatory compact



Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

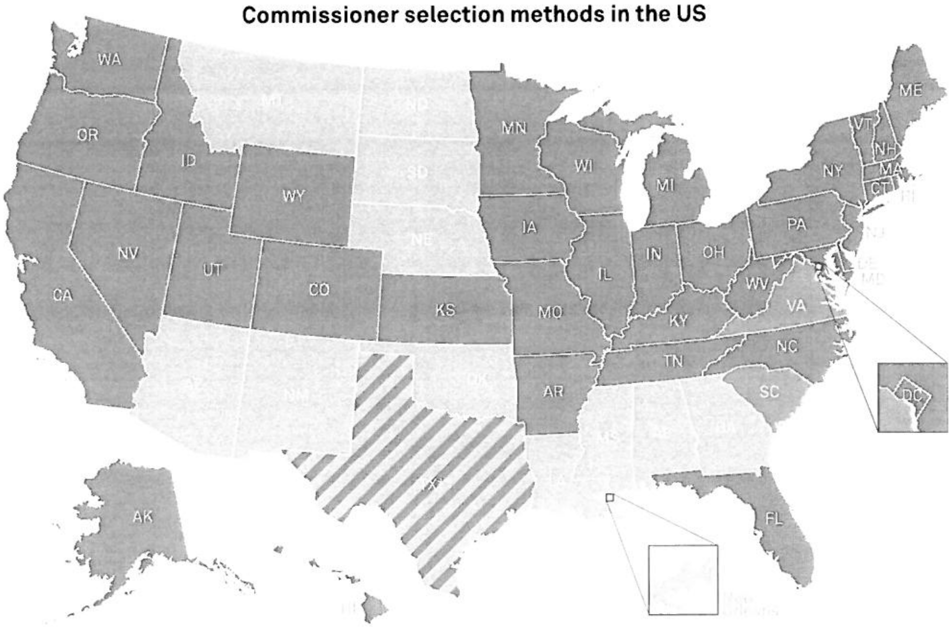
In these jurisdictions, the price of generation for "standard offer" customers — those who have not selected an alternative supplier — is generally set through an auction, a request-for-proposals process or through bilateral contracts between the competitive power suppliers and a separate state agency or the incumbent utility. In each of these jurisdictions, the resulting competitively determined price is passed on to the consumer, and the utility is simply a regulated deliverer of the power. Similar issues exist in the natural gas industry, where many customers have a choice of gas commodity suppliers; however, the distribution function continues to be the responsibility of the utility.

Since there is no market-based approach to setting utility rates, with the exception of the limited cases mentioned above, a cost-of-service methodology is used, whereby the commission examines the utility's costs and capital investments, determines whether they were prudently incurred, and then adds a risk-adjusted return for the utility's shareholders to the prudent costs to be recovered. This figure, known in industry parlance as the "revenue requirement," is then translated, in most instances, into a combination of a fixed monthly charge and an additional usage-based charge, per kilowatt-hour for an electric utility or per therm for a gas utility, which are used to determine each customer's total monthly bill.

The commissioners

Utility commissions in the U.S. have between three and seven members. In most jurisdictions, commissionerships are appointed positions, and these appointments are typically made by the chief executive of the jurisdiction. However, in 15 jurisdictions, utility commissioners are elected. Commissioners have considerable influence over utility policies and rate case outcomes, and some jurisdictions are more politicized than others. For an overview of the selection process at the state and federal utility regulatory agencies followed by Regulatory Research Associates, a group within S&P Global Market Intelligence, refer to the 1/14/20 Topical Special Report entitled "The Commissions." For detailed information on the composition of each commission and its unique policies, refer to RRA's Commission Profile pages.

Commissioner selection methods in the US



Appointed   Direct voter elections; elected by district   Elected by General Assembly   Other

Data as of May 15, 2020.
* The Public Utility Commission of Texas members are appointed by the governor, while members of the Railroad Commission of Texas are elected in statewide elections
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

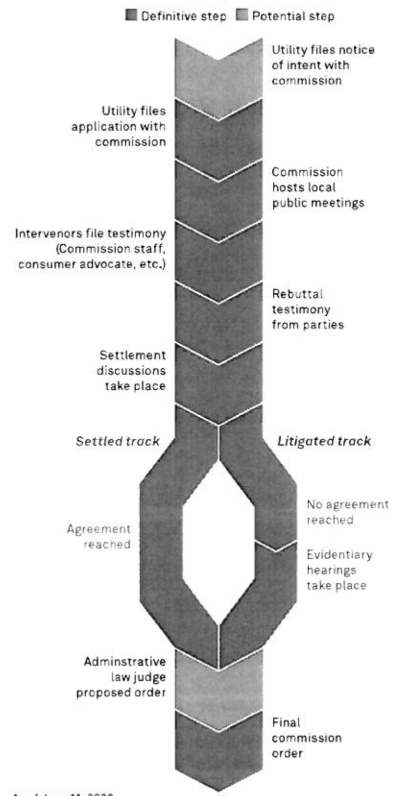
The rate case process

If the utility finds itself in a position of needing to raise its prices, the company must come before its state commission and file a rate case, unless it is already required to initiate rate proceedings at regular intervals. The reasons for a rate case filing are numerous, but they are generally due to investments the utility has been making, changes in expenses and cost of capital, and the impact of broader economic forces such as inflation or a sluggish economy.

A rate case is a quasi-judicial process, although there is no jury and the final outcome is determined by the commission. In some jurisdictions, the commission presides over the hearings and all aspects of a case, but in most instances the commissioners get involved at the end of the proceeding and make their decision after reviewing the entire case record. The process is complicated and costly, sometimes taking as long as two years to be completed. Utilities do not enter into a rate case lightly.

The process begins with the utility's filing, which includes the testimony of several witnesses. The company quantifies the additional revenue it believes it needs to recover its operating costs, depreciation expense and taxes, and to allow its shareholders to earn a reasonable return. Each witness supports a specific aspect of the company's filing, e.g., depreciation, rate of return or pension costs. The commission will schedule a series of local public hearings that offer ratepayers an opportunity to speak their mind about whatever it is the utility is proposing. The commission is not supposed to let the comments from these hearings factor into their decisions on case-specific issues because the comments are not part of the case record. However, commissioners are not immune to the public outcry that often accompanies a rate case.

Rate case process*



As of June 11, 2020.
* Action may take place depending on commission rules and procedures.
Credit: Cat Weeks
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

At some point during the process, after the intervenors have had a chance to digest the company's application, they will file their direct testimony, in which they outline their recommendations on the proposals put forth by the company. The parties will critique nearly every aspect of the utility's request, with the recommendations tailored to suit the needs of the relevant constituent group. Usually the commission's staff, a state attorney general and/or another state agency represent the public interest, primarily as it relates to residential customers, and their stance on rate case matters tends to be very different from that of the company. Every jurisdiction is different, but intervening entities can also include an individual large commercial or industrial customer or a consortium of such customers that may have a rather limited focus, a municipality or group of municipalities in which the utility operates, a group seeking to advance an environmental agenda and/or an organization that advocates for the needs of a particular segment of the population, such as retired ratepayers.

After this initial round of testimony, more testimony is filed in which the parties address their concerns with the positions taken in earlier rounds, and sometimes they will hold firm on their positions. But more often than not, the parties will begin settlement discussions to see if they can arrive at some sort of middle-of-the-road position on some or all of the outstanding issues in the proceeding. At the very least, this will narrow the gap between the parties' respective revenue requirement positions. If a consensus is reached regarding a stipulated rate increase, then the parties — at least some of them — will sign a settlement and file it with the commission. A settlement will generally shorten the time frame required to complete a rate case, since some of the other steps in the process can be eliminated.

If the parties are unable to reach a comprehensive agreement on the outstanding issues, the case will proceed on a litigated track, and the commission will need to rely on the evidence in the case as it develops a final decision on the issues. Frequently, a commission administrative law judge will issue a proposed order, effectively a recommendation, for the commissioners to consider for approval. At this point, the commissioners will hold a meeting and vote on a final order, and some commissions allow the public to listen in on their dialogue. The public may still not know what is included in the order but at least can feel that they are informed. Other commissions will simply issue their order with little advance notice.

Although the commission may have issued a final order, the case may not be completed, especially litigated cases, as the utility and some of the intervenors may not agree with aspects of the commission's order. The company may feel that the authorized ROE is out of line with prevailing industry returns, or the consumer advocate or attorney general may contend that the commission had no legal justification for allowing implementation of a rate rider.

For parties with objections to the final outcome, the initial remedy would be in the form of a request for reconsideration, and the parties can attempt to substantiate their claims. From that point, the commission could either simply affirm or amend the order in light of a new or compelling argument presented during the reconsideration process.

Once the commission acts on the requests for reconsideration, any further amendatory requests would need to be made in the form of a legal appeal to a court with jurisdiction over the commission's orders. The appeals process can be drawn out, and it is not uncommon to see utility rate matters get tied up in court for several years. However, a commission order being on appeal does not mean that the utility is prohibited from filing a new rate case, as the appeal process does not have to play out in its entirety before another case can be filed. By and large, most commission decisions typically have been upheld by the courts, but the court may remand or reverse a decision if the commission's ruling is determined to be in violation of the law.

The importance of the test year

An analysis of a utility's revenue requirement begins with the selection of a test year, which is simply a 12-month period used as a base line in examining the utility's actual revenues and expenses if a historical test year is chosen or a future 12-month period with a forecast of the utility's revenues and expenses if a fully forecast test year is selected. A hybrid approach of both methods can also be used.

Using its test-year financial data as the starting point, the utility proceeds to make adjustments for items that may not be representative of its operations going forward. For example, the utility may have filed a rate case on Jan. 1, 2020, and chosen a test year that ended on June 30, 2019. A wage increase for the company's unionized employees may have become effective in September 2019, but is not reflected in the financial results for the 12 months ended June 30, 2019. The approved rate change will not be implemented until late-2020, at which point the wage increase has long since been in place, so the utility will adjust its per-books labor expense level upward to reflect this in the new case.

Alternatively, the summer cooling season for an electric utility during the test year could have been abnormally hot, and the company's kilowatt-hour sales could have been abnormally high. In that situation, an adjustment to the utility's test year revenues could be warranted, which all else being equal, would have the effect of showing a greater need for a rate increase. Ideally, the utility will seek to select a test year and make appropriate adjustments to provide a representative picture of what its financial performance will be like during the first year that the new rates are in effect.

Determining the revenue requirement

Since the traditional utility revenue requirement formula is based on costs, the process used to determine a utility's revenue requirement begins with the expression below. At this point, this is pure accounting and not unique to the utility space.

Revenue	Operating expenses	Depreciation	Taxes	Net operating income

In the next equation, revenue has been isolated and renamed "revenue requirement."

Net operating income	+	Operating expenses	+	Depreciation	+	Taxes	=	**Revenue requirement**

In the third iteration of the formula, net operating income, or NOI, has been replaced with the product of the utility's rate of return and its net assets. Since NOI includes the funds necessary to service all the utility's securities, e.g., debt, preferred stock and common stock, NOI must equal the product of the overall rate of return, or cost of capital, and the asset base. It is essentially the pool of money left over for investors after all the direct costs of doing business have been satisfied.

Rate of return	×	Net assets	+	Operating expenses	+	Depreciation	+	Taxes	=	**Revenue requirement**

In the fourth version, net assets has been renamed "rate base," which is a regulatory term that refers to the company's net utility assets, as determined by the commission, that are "used and useful" in the provision of service to ratepayers.

Rate of return	×	Rate base	+	Operating expenses	+	Depreciation	+	Taxes	=	**Revenue requirement**

Calculating the rate change

The above equations give rise to the company's total revenue requirement. However, the process must shift to the determination of the *rate change* that is required so that the company can collect its total revenue requirement. In simple terms, the commission reviews the utility's revenue and prudent costs for the selected test year and considers the resulting NOI for that period. If the company's NOI is determined to be inadequate, a rate increase is authorized. Conversely, if the NOI is found to be too high, a rate reduction can be ordered.

The following expression is the common formula for calculating a rate change, which in industry speak means the additional revenue the utility is proposing, or that an intervenor is recommending or that the commission is authorizing. The equation has three variables — or four, if the tax factor is considered — and these variables are shown with an asterisk; everything else is the result of plugging the appropriate variable into the equation.

Calculating the rate change

	Rate of return*
x	Rate base*
	Required NOI
—	NOI under current rates*
	NOI deficiency
x	Tax factor
	Rate adjustment

*Indicates that figures are variables and not the result of a calculation in the equation.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Rate of return — The first variable in the expression is the rate of return, which is the result of a weighted-average cost of capital calculation and generally includes the cost of debt and the cost of equity.

While the cost of a company's debt securities can be gleaned by reviewing the stated cost rates for each particular debt issue, there is no stated return for common equity. If an investor were to buy a utility stock, he or she would not be promised any specific return on their investment. There is no coupon rate for common equity, and the return will simply be the sum of any dividend income the investor will receive over time and the price appreciation or reduction experienced during the holding term.

What does this mean in terms of calculating the ROE? It means that informed individuals can disagree on what the appropriate return should be, even though they rely on established financial theory to arrive at an estimate for the cost of equity. In utility rate cases, the estimated ROE is very subjective, and even slight variations to the inputs in the formulas commonly used can produce significant differences between what each party thinks is an acceptable equity return for the company.

Rate base — The second variable shown in the rate change calculation is the rate base value. At a very basic level, rate base is a utility's prudent capital investment, as authorized by the commission, net of accumulated depreciation. Rate base may include other items such as commission-approved deferred costs known as regulatory assets, certain pension contributions and items that may be used to offset the value of rate base, such as accumulated deferred income taxes, or ADIT, and customer deposits. But in its simplest form it is the used-and-useful net asset base from which the utility provides service to customers and upon which it is allowed to earn a rate of return.

For electric utilities doing business in non-restructured jurisdictions, rate base includes the net value of investments in generation, transmission and distribution infrastructure. In states that have restructured their electric markets and where the generation supply is now competitively procured, the generation assets are no longer included in the rate base calculation. In restructured jurisdictions, legacy utility generation plants have either been divested entirely to a merchant generation company or transferred to an affiliate of the utility, and these plants are no longer economically regulated.

For gas utilities, rate base includes the pipes and mains that are used in the provision of distribution service. But when it comes to valuing rate base, many other items can be included in or used to offset the net value of the utility's plant and equipment. For example, equipment inventories are typically included in rate base, as is cash working capital, which is the amount of cash required by a utility to pay the day-to-day expenses incurred to provide service to customers.

Calculating rate base can be complicated due to certain policy considerations. For example, what period of time should the commission use to measure rate base? Should it be a specific historical date, with "known-and-measurable changes" recognized? Should it be a date in the future that contains projections? Using projections generally produces a higher rate base. Should rate base be determined as of the end of the rate case test year — a year-end valuation — or should it be based on the average of the monthly rate base values over the course of the test year? Does the commission include construction work in progress, or CWIP, in rate base?

Including CWIP in rate base allows the utility to collect a cash return on the asset under construction prior to completion. If CWIP is not included in rate base, accounting standards dictate that the utility is to record a non-cash adder known as allowance for funds used during construction, or AFUDC, which represents the accrued financing charges associated with CWIP that is not yet included in rate base. AFUDC is equal to the assumed rate of return on the CWIP balance, with the amount included on the utility's income statement during the period in question. With AFUDC, earnings remain whole during construction, but there is no impact on the company's cash flows. Once the plant is completed, the accumulated AFUDC is generally included in rate base as plant-in-service. Several states have statutes that prohibit the inclusion of CWIP in rate base.

Regulatory assets, which are also frequently included in rate base, are unique to utilities and are the product of accounting standards. A regulatory asset is created when the utility's regulator authorizes the deferral, to a future period, of a given expense — including depreciation and storm restoration expense — that would normally be recorded on the company's income statement during the present period. Accounting convention says that the prospects for future recovery, in rates, of the cost item in question must be probable for an expense to be deferred. The deferred costs give rise to a regulatory asset that is likely, but not guaranteed, to be included in rate base at some point in the future and amortized over a number of years. Regulatory assets are not generally physical plant assets, and this is one of the reasons why simply taking the value of the company's net plant as a proxy for rate base is not advisable.

State utility commissions have approved the use of deferral techniques for various costs in recent years, perhaps most prominently for costs incurred to restore service after large storms. Few industry participants ever imagined that similar measures might need to be taken to respond to the effects of a pandemic. However, several jurisdictions are examining the merits of using deferral treatment to address changes to utility cost profiles and "lost revenues" due to COVID-19.

Proposals to defer lost revenues are similar to what would occur with a decoupling mechanism. A decoupling mechanism essentially allows the utility to defer fixed costs that it fails to recoup through volumetric charges due to customers' participation in conservation programs, weather fluctuations or altered economic conditions, changes in demographics or even the departure of a large customer. The utility is then allowed to recover the deferrals associated with the unrecovered fixed costs through a mechanism over a period of time, generally with carrying charges on the deferred balance.

ADIT arises due to the tax timing differences created by the alternate depreciation calculations from the straight-line method, which is used for financial statement purposes, and the accelerated method that is used for tax purposes. The utility is collecting, at present, a portion of the tax liability it will owe at some point in the future, and the cost-free funds need to be accounted for. ADIT can either be accounted for as a reduction to rate base, as is the case in most jurisdictions, or as a source of zero-cost capital in the rate-of-return calculation. If an analyst were to leave ADIT out of the rate base calculation, they would be artificially inflating their estimate of the utility's rate base, and accordingly, its revenue requirement.

Capital structure (%)

Atmos Energy Corp. — PSC Case No. 2018-00281

Type of capital	Percent of capitalization	Cost rate	Weighted-cost rate
Long-term debt	39.73	4.56	1.81
Short-term debt	2.21	3.40	0.08
Common equity	58.06	9.65	5.60
	100.00		7.49

Regulatory capital structure

Northern Indiana Public Service Co. — IURC Ca. No. 44988

Type of capital	Percent of capitalization	Cost rate	Weighted-cost rate
Long-term debt	36.80	4.94	1.82
Customer deposits	1.22	4.91	0.06
Deferred income taxes	21.10	0.00	0.00
Prepaid pension asset	-7.43	0.00	0.00
Post-employment liability	1.39	0.00	0.00
Post-1970 investment tax credits	0.04	7.69	0.00
Common equity	46.88	9.85	4.61
	100.00		6.50

Data compiled June 11, 2020.
PSC = Kentucky Public Service Commission; IURC = Indiana Utility Regulatory Commission
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Examples of capital structures determined using these methodologies are depicted above. On the top of the figure, a traditional capital structure is shown, while the one on the bottom includes deferred income taxes as a zero-cost item. The vast majority of jurisdictions use a traditional capital structure; Arkansas, Florida, Indiana and Michigan rely on the alternative technique.

NOI under current rates — The third variable in the equation is NOI under current rates, which is basically the NOI the utility would be expected to achieve if its rates were to be left unchanged. This figure is pulled from the financial exhibits the utility submitted in its rate case application and includes adjustments such as employee wage increases. It is another variable that can vary considerably in a rate case.

As an example, increased executive incentive compensation expense, all else being equal, would lead to a lower NOI under current rates, and, working through the rate change formula shown previously, a greater need for a rate increase. But this variable cuts both ways. The intervenors in a rate case might recommend that a portion of the company's executive incentive compensation expense be disallowed and excluded from the calculation of this variable if it is demonstrated that the cost was tied to a financial metric that only benefitted shareholders. Disallowing recovery of these costs would result in a higher NOI under current rates and would lead to a lesser need for a rate increase. The list of potential NOI adjustments is extensive, and there is ample opportunity for the company and the parties to propose adjustments that can significantly impact the revenue requirement in the case.

The required NOI will be compared to the NOI under current rates, and the difference is referred to as the NOI deficiency, indicating a need for a rate increase, or the NOI sufficiency, suggesting that rates should be reduced. This is a net amount that needs to be grossed up for taxes, since the utility is permitted to collect amounts that will be remitted to its taxing authorities. Generally speaking, corporate taxes will take a 20%-25% bite out of pretax income, so multiplying the NOI deficiency or sufficiency by about 1.35 — the reciprocal of 75% — will give the top-line revenue change number.

Rate design

Once a utility's revenue requirement has been determined, the task of establishing a new set of tariffs has to be tackled. The approved change in revenues needs to be allocated to each customer class before new rates can be implemented. Generally speaking, the utility's revenue requirement is supposed to be collected from each customer class according to the relative share of the company's cost to serve those customers. There are different methodologies for doing this, but they all attempt to allocate the utility's cost of service in a justified manner, at least in theory. The reality is that sometimes one class ends up being allocated a disproportionate share of the revenue requirement. Residential customers vote and utility matters tend to be politicized, and regulators, especially those that are elected to their positions, may be reluctant to elicit backlash from residential ratepayers. In such a situation, the commercial and industrial customer classes could be hit with an above-average share of a rate increase. On the other hand, some jurisdictions may be trying to attract new businesses to their area for economic development reasons and could be inclined to allocate a larger-than-average share of any approved revenue increase to the residential class. The circumstances can vary widely by jurisdiction, and there is no one-size-fits-all approach to revenue requirement allocation. But inter-class subsidies do exist.

The revenue requirement for each class will need to be divided by the estimated number of units of the product that will be sold over the next 12 months. For an electric utility that serves 75,000 residential electric customers that are forecast to use, on average, 1,000 kilowatt-hours per month, 900 million kilowatt-hours are sold in total, or 900,000 megawatt-hours, per year. If the utility has been authorized a $7 million base rate hike, of which $3 million has been allocated to the residential customer class, then that $3 million in additional revenue will need to be converted into a per-unit charge that will ultimately be used in determining each customer's monthly bill. Dividing $3 million by 900 million kilowatt-hours gives 3 tenths of 1 cent. So a residential customer of this utility would be paying an extra $3 per month going forward, or $36 per year.

Estimating the ROE

There are several methodologies for estimating an ROE for a utility in a rate case, although there are a select few that are consistently recognized by utility commissions.

<u>*Discounted cash flow, or DCF*</u> — The DCF model calculates ROE by dividing the company's dividend, in dollars, by its observable market price and then adding an assumed growth rate, as shown below.

Dividend/ market price	+	Growth rate	=	**Required return on equity**

If a company's dividend is expected to grow at different rates over a period of time, then a multistage DCF approach can account for this. The DCF model is one of the standard formulas for estimating ROE in rate cases, but as is the case with any formula or model, the output is only as good as the inputs, so it is important to make reasonable assumptions regarding the growth rate.

<u>*Capital Asset Pricing Model, or CAPM*</u> — The CAPM is also given significant weight by the commissions and is depicted below.

Risk-free rate	+	(	Expected market return premium	×	Utility stock's beta	)	=	**Required return on equity**

The CAPM uses as the starting point for determining the ROE the yield on a long-term U.S. Treasury bond. This rate is the risk-free rate of return in the formula. Since all securities are, by definition, riskier than the riskless government bond, an ROE for those securities will need to reflect some sort of premium over the risk-free return. The CAPM approach adds the product of the stock's beta — the systematic risk factor for the company, calculated by looking at the relationship between the stock's historical price movements and those of the broader market — and a market return premium. The market return premium is simply the expected "excess" return for the stock market over the risk-free rate and is also calculated with historical price movements in mind. The sum of the risk-free rate and the product of the stock's beta and the market return premium will give an estimate of an appropriate ROE for a utility.

Comparable earnings — Many commissions consider the results of a comparable earnings analysis when establishing an authorized ROE. This approach assumes that a given investment should earn a return similar to that of investments with similar risk characteristics. Generally speaking, utility commissions have a preference for the DCF and CAPM methodologies and, instead of relying on one or the other, will often take an average of the ROE estimates these two models produce.

Certain factors may impact the ROE ultimately authorized. For example, if the utility is an electric distribution company with no regulated generation assets, the commission may consider this company to be a lower-risk entity and authorize a slightly lower ROE than it would for a fully integrated electric company. In addition, commissions may authorize a slightly lower ROE for companies that utilize several adjustment clauses that allow for timely recognition of changes in certain expenses outside of a general rate case. Over the years, there have also been ROE authorizations that reflected incentive awards for superior management performance or less-than-stellar service quality.

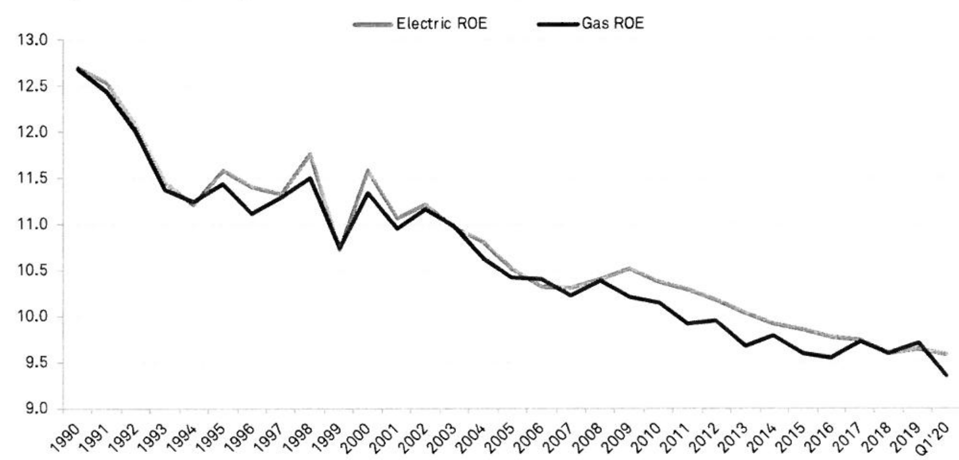
The bottom line is that there is no "correct" way to calculate an appropriate ROE. As is the case with most financial models, the output is only as good as the input, which means that estimating the variables in any ROE formula is an important undertaking.

Authorized Energy ROEs – a temporal analysis

Through the first three months of 2020, the average ROE authorized for the electric utilities nationwide was 9.58%, including limited-issue proceedings where in many instances incentive ROE premiums were included; excluding these cases from the data, the average authorized ROE was 9.45%. The average ROE authorized for the gas utilities over this same period was 9.35%, a historic low. These returns are roughly 300 basis points lower than they were in 1990. As demonstrated in the following chart, there are relative movements from one year to the next, but the trend is clear.

The gap between the authorized ROEs for electric and gas utilities was relatively tight in the early 1990s, when authorized ROEs for both sides of the business tended to move in lockstep. Beginning later that decade, the gap narrowed even further following the advent of electric industry restructuring. As certain states restructured their electric markets, their utility commissions began to authorize slightly lower equity returns for the electric utilities that had become essentially just transmission and distribution, or T&D, utilities. Thus, the ROEs shown for the electric utilities reflect a blend of ROEs approved for integrated and T&D-only utilities.

Average electric and gas authorized ROEs (%)



Data compiled on June 9, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

The relationship between authorized ROEs for electric and gas utilities generally held for much of the 1990s and continued into the 2000s, and around the middle of the decade, the gap began to widen. In the last 10 years or so, the gap has been as much as 30 to 40 basis points, largely due to ROE premiums that are being accorded certain generation projects. Due to the sheer magnitude of the costs involved with building new generation, regulators in some jurisdictions have found it worthwhile to incentivize utilities to proceed with these projects through plant-specific ROE premiums. In recent years, however, the returns have again begun to narrow.

Authorized vs. earned ROEs

A utility's authorized ROE is that which has been specified by the commission in a rate case for the company. It is used to calculate the overall return that is applied to the utility's rate base and is reflected in the rates that customers are charged. By contrast, the earned ROE reflects actual results achieved by the company over a period of time. The two numbers do not have to be equivalent and are usually not.

Commissions are required by the regulatory compact to provide the utility with a "reasonable opportunity" to earn the authorized ROE, but that is by no means a guarantee. Utilities are not guaranteed any sort of return by their regulators, although for some regulatory frameworks that are based on a formulaic or performance-based ratemaking structure, this is not necessarily true. But those circumstances are not the norm.

Assuming the commission did not adopt any meaningful disallowances in the utility's most recent rate case and the test year that was used in the case was not too old, the company may be able to earn that return if it operates the business efficiently. However, for those utilities that are continually subject to regulatory lag — meaning that their authorized revenue requirement does not reflect the full value of the investments that are currently being used to provide service — they may never be able to earn their authorized ROEs.

Rate case example

In a gas rate proceeding decided in 2019 for Atmos Energy Corp., the company had supported a $14.4 million rate increase. The company used a test year that was fully forecasted at the time the case was initiated. Ultimately, the company supported a rate base that was valued at $496 million, a 10.4% ROE and a 7.93% overall return. Atmos said that its requested increase was necessitated by a "declining return on equity and inadequate revenue to continue to provide the quality of service required by the commission and demanded by our customers."

In the Kentucky Public Service Commission's final order in the case, the commission required the company to reduce base rates by $0.3 million based on a 9.65% ROE, a 7.49% overall return and a $424.9 million rate base. The authorized overall return was lower than that supported by the company, the adopted rate base was lower and the NOI under current rates was higher. Each of these adjustments served to lower the revenue requirement relative to the rate increase that had been supported by Atmos. As shown in the accompanying table, the PSC's adjustments in this proceeding totaled roughly $15 million, representing the difference between the $14.4 million rate increase supported by Atmos and the $0.3 million reduction ordered by the commission.

Atmos Energy Corp.

	Company supported	PSC ruling	Approx. difference ($M)
Rate of return*	7.93%	7.49%	3
x Rate base ($M)*	496.0	424.9	8
Required NOI ($M)	39.3	31.8	
— NOI under current rates ($M)*	28.7	32.0	4
NOI deficiency ($M)	10.6	-0.2	
x Tax factor	1.35	1.35	
Rate adjustment ($M)	14.4	-0.3	15

Data compiled June 11, 2020.
NOI = net operating income; PSC = Kentucky Public Service Commission
* Rate case variables.
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; PSC Case No. 2018-00281

Using the formulas below, RRA determined that about $3 million of the total difference stemmed from the PSC's decision to adopt a lower rate of return that than supported by the company. There was about $8 million of difference attributable to various reductions to rate base. NOI adjustments accounted for the remaining roughly $4 million of the revenue requirement difference.

On balance, RRA deemed this decision to be negative from an investor viewpoint. Although the 9.65% ROE authorized by the PSC approximated the average of returns accorded gas utilities nationwide during the 12 months preceding the decision, the PSC rejected Atmos' request to terminate its pipeline replacement program, or PRP, rider and reflect all prospective costs associated with its accelerated infrastructure upgrades in annual base rate filings. However, the commission acknowledged certain concerns the company had with the nature of the PRP rider proceedings. In addition, the PSC took issue with the company's failure to request preapproval of certain projects through a process outlined in state law. The commission made it clear that it would view similar actions in the future unfavorably.

Revenue requirement differences (approximate)

Variable #1 Difference in return

Atmos' ROR	7.93%
— PSC ROR	— 7.49%
ROR difference	0.44%
x PSC rate base	x $424.9 (million)
Net revenue req. difference	$1.9 million
x Tax factor	x 1.35
Revenue req. difference	$3 million

Variable #2 Difference in rate base

Atmos' rate base	$496 million
— PSC rate base	— $424.9 million
Rate base difference	$71.1 million
x Atmos's ROR	x 7.93%
Net revenue req. difference	$5.6 million
x Tax factor	x 1.35
Revenue req. difference	$8 million

Variable #3 Difference in NOI

PSC NOI	$32.0 million
— Atmos' NOI	— $28.7 million
NOI difference	$3.3 million
x Tax factor	x 1.35
Revenue req. difference	$4 million

Data compiled June 11, 2020.
PSC = Kentucky Public Service Commission; ROR = rate of return; NOI = net operating income
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence; PSC Case No. 2018-00281

Rate case activity

Electric and gas rate case activity has been quite robust in recent years. Through the first five months of 2020, there were 48 major rate case decisions in the U.S. — 31 electric and 17 gas — and RRA expects an additional roughly 30 or more to be decided by year-end, which would bring the total number of decisions in 2020 to about 80.

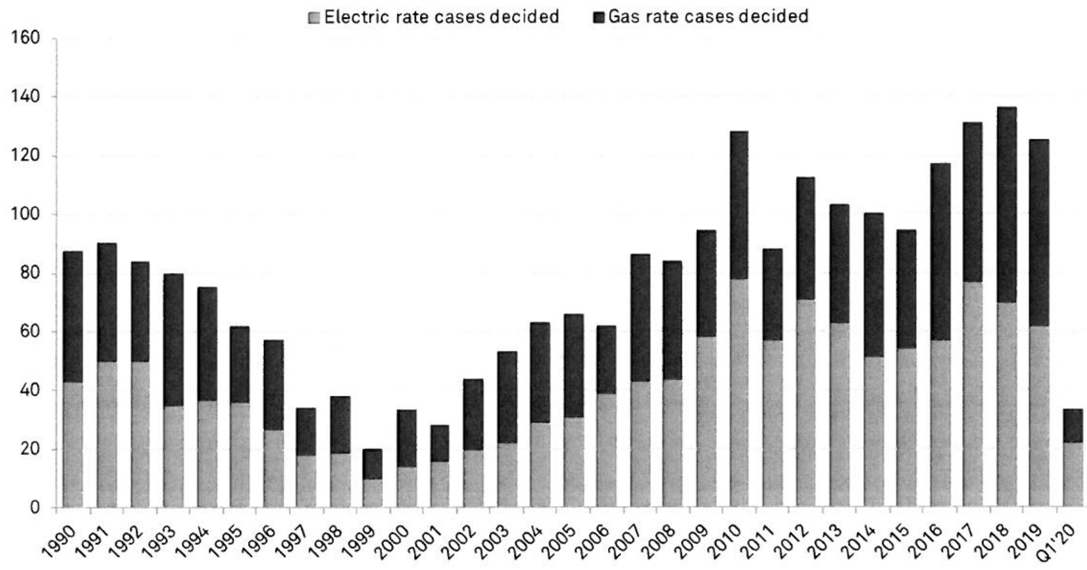
Even though recent activity is fairly robust by current standards, it still has not reached the levels seen in the 1980s, when as many as 200 cases were decided in a single year, 1982. This level of regulatory activity was driven largely by the need to achieve rate recognition of new large-scale generation facilities, particularly nuclear facilities, inflation and rising interest rates.

Rate case activity continued to be significant through the first half of the 1990s but declined significantly in the latter part of the decade, reaching a 35-year low of 20 cases in 1999. This trend was largely due to cessation of major construction programs, the specter of electric industry restructuring/retail competition and declining interest rates.

During this period, "competition" for the electric generation portion of utility service was the industry's buzzword, and many utilities were attempting to minimize their retail prices in an effort to remain "competitive." In several states, the utility commissions established multiyear rate plans, under which rates were frozen during a transition period in which the utilities were permitted to recover stranded costs, i.e., the costs that were considered to be unrecoverable in a competitive retail market for electric generation service. The trend toward expanding retail competition has since been largely halted.

In addition, at the time interest rates were comparatively low, and many utilities had previously been authorized rates of return that were deemed to be much higher than those they could expect to be awarded in a new rate case. Also, construction activity had dropped following the end of the 1980s construction boom, and there were fewer large capital investments for which utilities would typically seek rate recognition. Consequently, there was little expectation that

Decided electric and gas rate cases



Data compiled June 9, 2020.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

a rate case would result in approval of a higher revenue requirement. In addition, technological improvements that reduced operating costs may have allowed the companies to delay filing new rate proceedings.

From 2000 through 2006, rate case activity increased somewhat but remained relatively sluggish due to the extensive rate freezes that had been required by many of the states that implemented retail competition as well as persistent declines in interest rates and authorized ROEs and a focus on cost-cutting and management efficiency.

Rate case activity picked up more sharply beginning in 2007, as the previously mentioned restructuring-related rate freezes expired and traditionally structured companies that had remained out of the rate case arena found that they could no longer use operational efficiency gains to offset the revenue requirements associated with new investments and increasing employee costs.

Rate case activity hit another peak in 2010 when 129 cases were decided, and in recent years, rate cases have continued to occur at a fairly brisk pace as utilities seek to: (1) achieve rate recognition of new investment in electric generation to meet new demand and satisfy environmental compliance obligations in vertically integrated jurisdictions as well as to meet renewable resource mandates; (2) reflect in rates electric and gas transmission and distribution infrastructure investments needed to remediate damage caused by severe weather, improve reliability, protect against future outages, replace aging infrastructure particularly on the gas distribution side in the wake of pipeline incidents, and deploy new technologies such as smart meters in order to facilitate energy conservation programs and renewables initiatives; (3) recover increasing employee healthcare and pension costs; and (4) address the earnings impact of reductions in sales volumes due to weather, customer participation in energy efficiency programs and weak economic conditions.

RRA expects this level of activity to continue for the foreseeable future, as many of the drivers of rate cases noted above represent complex issues that will need to be addressed over the long term. For a full list of past and pending rate cases, rate case statistics and upcoming events, visit the energy research home page.

Prevalence of adjustment clauses

Utility industry stakeholders have developed innovative techniques to achieve timely rate recognition of investments in certain projects and increases in key expenses. One such technique is the adjustment clause, which effectively shifts the risk associated with recovery of the expense in question from shareholders to customers, because, if the clause operates as designed, the company is able to change its rates to recover its costs on a current basis without any negative effect on the bottom line and without the expense and delay that accompanies a rate case filing.

The electric and natural gas utilities' use of adjustment clauses to recover variations in certain costs outside of the traditional rate case process has its origins in the 1973 Arab oil embargo, when fuel costs skyrocketed, leaving the utilities with no way to recover the increased costs in a timely manner. During these years, utility earnings were under considerable pressure, a situation that prompted some jurisdictions to establish a more constructive framework to allow more timely recovery of cost increases that were beyond the control of the utilities. The result was the creation of the fuel adjustment clause.

Over the ensuing years, the use of adjustment clauses expanded to include other expenses that are outside the control of the utility or are required by law or rule, such as environment compliance costs, conservation program costs, pension costs, municipal taxes and franchise fees, the pass-through of transmission-related costs allocated to the utility by the Federal Energy Regulatory Commission and storm costs, to name a few.

More recently, the use of adjustment clauses was expanded further to include certain types of new generation and T&D investment and to mitigate the impacts of fluctuations in sales due to weather, energy conservation and/or economic conditions. For a discussion of the most prominent adjustment clauses in place for the electric and natural gas utilities in the U.S., refer to the 11/12/19 Topical Special Report entitled Adjustment Clauses: a state-by-state overview.

Although not adjustment clauses per se, some jurisdictions have approved the use of surcharges to recover specific one-time items, such as excess storm restoration costs, while expense trackers have also been widely adopted. Expense trackers provide for the deferral of variations in certain costs for potential recovery at a future time, when the commission will consider the accumulated balance for inclusion in rates. Although an expense tracker is designed to keep the utility's earnings whole, rates, and accordingly cash flows, do not change on a current basis.

Alternative ratemaking

Another construct that is akin to a rate case but is designed to address ratemaking in a more streamlined fashion is broadly known as "alternative ratemaking." It can mitigate regulatory lag, which as discussed earlier can prevent the utility from earning its authorized return. Alternative regulation plans can be broadly or narrowly focused.

Broad-based plans include formula-based ratemaking plans that generally refer to frameworks where the commission has established a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost of service base rate proceeding. Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or period of years.

Under multiyear rate plans, the commission approves a succession of rate changes that are designed to take into account anticipated changes in revenues, expenses and rate base. The commission may approve a static authorized ROE or the plan may provide for adjustments to the ROE during the plan's term. These plans often include true-up mechanisms to ensure that the company makes the investments it has committed to make at the inception of the plan. The plans often include earnings sharing mechanisms and may also include performance-based ratemaking provisions.

Use of adjustment clauses (as of November 2019)

State/ Company	Ultimate parent ticker	Type of service	Type of adjustment clause: Electric fuel/gas commodity/purch. power	Conserv. program expense	Decoupling: Full	Decoupling: Partial	Renewables expense	Environmental compliance	New capital: Generation capacity	New capital: Generic infrastructure	RTO-related transmission expense	Other
ALABAMA												
Alabama Power Co.	SO	Elec.	✓ *	--	--	--	✓	✓ *	✓ *	--	--	✓ *
Spire Alabama Inc.	SR	Gas	✓ *	--	--	✓ *	--	--	--	--	--	✓ *
Spire Gulf Inc.	SR	Gas	✓ *	--	--	✓ *	--	--	--	--	--	✓ *
ALASKA												
Alaska Electric Light and Power Co.	AVA	Elec.	✓	--	--	--	--	--	--	--	--	--
Enstar Natural Gas Co.	ALA	Gas	✓	--	--	--	--	--	--	--	--	--
ARIZONA												
Arizona Public Service Co.	PNW	Elec.	✓	✓	--	✓ *	✓	✓	--	--	✓	✓ *
Southwest Gas Corp.	SWX	Gas	✓	✓	✓	-- *	--	--	--	✓ *	--	✓ *
Tucson Electric Power Co.	FTS	Elec.	✓	✓	--	✓ *	✓	✓	--	--	--	✓ *
UNS Electric Inc.	FTS	Elec.	✓	✓	--	✓ *	✓	--	--	--	✓	✓ *
UNS Gas Inc.	FTS	Gas	✓	--	--	✓ *	--	--	--	--	--	✓ *
ARKANSAS												
Arkansas Oklahoma Gas Corp.	--	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
CenterPoint Energy Resources Corp.	CNP	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
Entergy Arkansas LLC	ETR	Elec.	✓	✓	--	✓ *	✓	--	✓ *	✓ *	✓	✓ *
Oklahoma Gas and Electric Co.	OGE	Elec.	✓ *	✓	--	✓ *	✓	✓	✓	--	✓	✓ *
Black Hills Energy Arkansas Inc.	BKH	Gas	✓	✓	✓	--	--	--	--	✓ *	--	✓ *
Southwestern Electric Power Co.	AEP	Elec.	✓	✓	--	✓ *	--	✓	✓	--	✓	✓ *
CALIFORNIA												
Pacific Gas & Electric Co.	PCG	Elec.	✓	--	✓	--	--	--	--	--	--	✓ *
Pacific Gas & Electric Co.	PCG	Gas	✓	--	✓	--	--	--	--	--	--	--
San Diego Gas & Electric Co.	SRE	Elec.	✓	--	✓	--	--	--	--	--	--	✓ *
San Diego Gas & Electric Co.	SRE	Gas	✓	--	✓	--	--	--	--	--	--	--
Southern California Edison Co.	EIX	Elec.	✓	--	✓	--	--	--	--	--	--	✓ *
Southern California Gas Co.	SRE	Gas	✓	--	✓	--	--	--	--	--	--	--
Southwest Gas Corp.	SWX	Gas	✓	--	✓	--	--	--	--	--	--	--

Earnings sharing mechanisms allocate to ratepayers and shareholders earnings that differ from a target or target range established by the commission. These mechanisms can also be implemented as part of formula rate plans and multiyear rate plans, in conjunction with a rate freeze, as part of a merger related filing or on a stand-alone basis as part of a rate case.

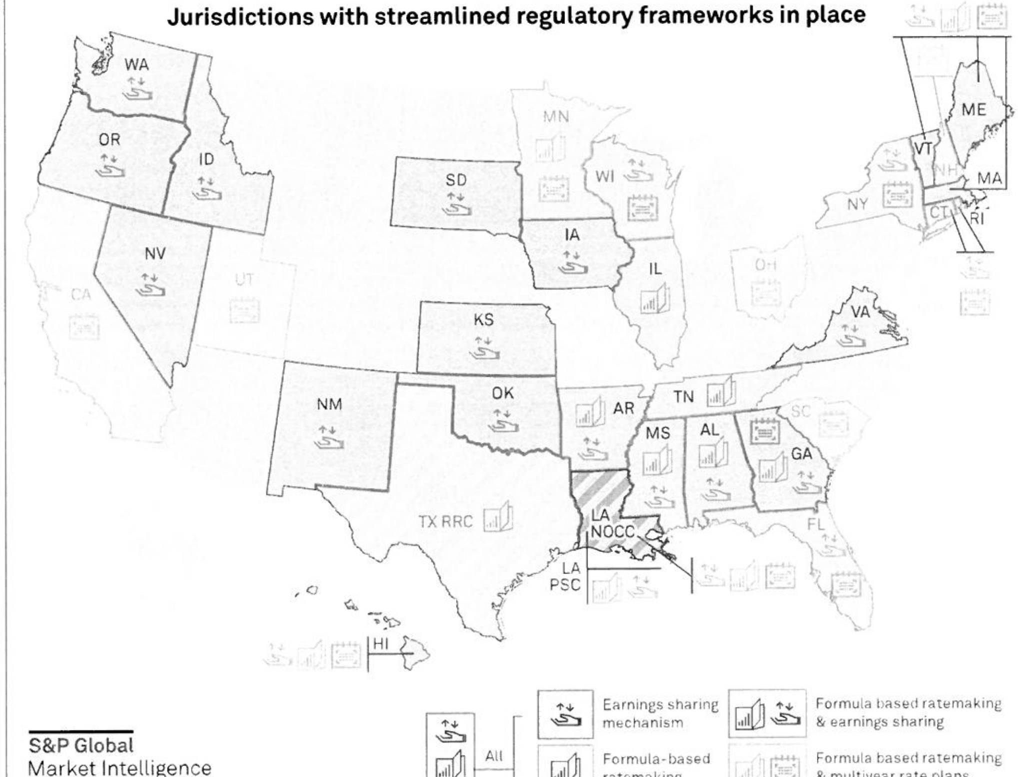
As of April 2020, 13 of the 53 jurisdictions followed by RRA had formula based ratemaking plans in place for at least one company in the jurisdiction, including jurisdictions where such plans were combined with other mechanisms. There are 17 jurisdictions in which a multiyear rate plan is in place for at least one utility, including instances where it is combined with other types of plans. Earnings sharing mechanisms are in place for at least one utility in 25 jurisdictions, on a stand-alone basis or as part of either a multiyear plan or a formula-based ratemaking mechanism. In a handful of other jurisdictions, legislation or commission rules permit these types of plans, but the commission has yet to approve a specific plan for one of the utilities.

Narrowly focused plans generally target a specific type of behavior or investment on the part of a utility. For example, some may allow a company to retain a portion of cost savings relative to a base level of some expense type, such as fuel, purchased power or pension costs.

Others might permit a company to retain for shareholders a portion of off-system sales or capacity release revenues. Still others provide a company an enhanced ROE for achieving operational performance targets, customer service metrics, reliability standards, demand reduction targets under energy conservation programs or for meeting or exceeding renewable portfolio standards.

In some instances, commissions have approved ROE premiums for specific types of plant investment when there was a preference for in-state generation versus wholesale power purchases, or in order to incent the deployment of renewable resource facilities.

Jurisdictions with streamlined regulatory frameworks in place



S&P Global
Market Intelligence

As of March 31, 2020.
Map credit: Ciaralou Agpalo Palicpic
Source: S&P Global Market Intelligence

While narrowly focused plans do not necessarily stream line the regulatory process the way that more broadly focused plans do, they do provide the utilities with the opportunity for earnings enhancement that could offset the impact of regulatory lag.

As utilities continue to grapple with increasing capital requirements and a shifting utility landscape, RRA expects increased use of these and new types of alternative regulation frameworks. For a discussion of the alternative ratemaking frameworks currently in place in each jurisdiction, refer to the Alternative Regulation section of the state Commission Profiles.

Contributors: Charlotte Cox, Jim Davis, Lillian Federico, Lisa Fontanella, Jason Lehmann, Dan Lowrey, Amy Poszywak.

S&P Global
Market Intelligence

May 25, 2021
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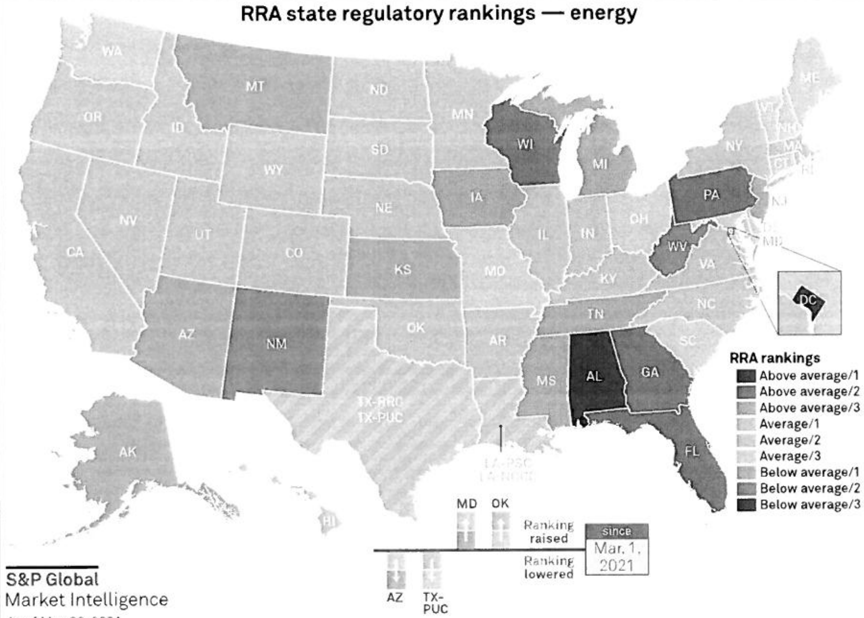
RRA Regulatory Focus
State Regulatory Evaluations

Assessments of regulatory climates for energy utilities

Regulatory Research Associates, a group within S&P Global Market Intelligence, evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia, a total of 53 jurisdictions, on an ongoing basis. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by each jurisdiction's energy utilities.

RRA state regulatory rankings — energy



S&P Global
Market Intelligence
As of May 20, 2021.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission
Map credit: Joe Felizadio
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Each evaluation is based upon consideration of the numerous factors affecting the regulatory process, including gubernatorial involvement, legislation and court activity, and may be adjusted as events occur that cause RRA to modify its view of the regulatory risk for a given jurisdiction.

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RRA State Regulatory Evaluations *
Energy

Above Average 1	Average 1	Below Average 1
Alabama	Arkansas Colorado Indiana Kentucky Nebraska North Carolina North Dakota Virginia	Alaska Arizona Kansas Montana New Jersey
Above Average 2	**Average 2**	**Below Average 2**
Florida Georgia Pennsylvania Wisconsin	California Hawaii Idaho Illinois Louisiana-PSC Massachusetts Minnesota Nevada New York Oklahoma Oregon Rhode Island South Dakota Texas RRC Utah Wyoming	New Mexico West Virginia
Above Average 3	**Average 3**	**Below Average 3**
Iowa Michigan Mississippi Tennessee	Connecticut Delaware Louisiana-NOCC Maine Maryland Missouri New Hampshire Ohio South Carolina Texas--PUC Vermont Washington	Dist. of Columbia

As of May 20, 2021.
NOCC = New Orleans City Council;
PSC = Public Service Commission;
PUC = Public Utility Commission;
RRC = Railroad Commission
*Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

RRA also reviews evaluations as key rate case and other regulatory decisions are issued when updating Commission Profiles and when publishing this quarterly comparative report. The issues considered are discussed in RRA Research Notes, Commission Profiles, Rate Case Final Reports and Topical Special Reports. RRA also considers information obtained from contacts with commission, company and government personnel in the course of its research. The final evaluation is an assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative and court actions.

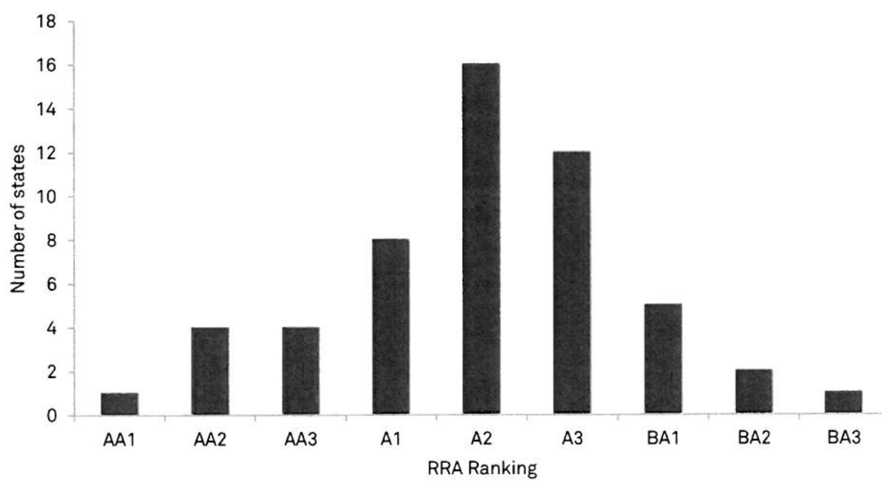
An Above Average designation indicates that, in RRA's view, the regulatory climate in the jurisdiction is relatively more constructive than average, representing lower risk for investors that hold or are considering acquiring the securities issued by the utilities operating in that jurisdiction.

At the opposite end of the spectrum, a Below Average ranking would indicate a less constructive, or higher-risk, regulatory climate from an investor viewpoint.

A rating in the Average category would imply a relatively balanced approach on the part of the governor, the legislature, the courts and the commission when it comes to adopting policies that impact investor and consumer interests.

Within the three principal rating categories, the designations 1, 2 and 3 indicate relative position, with a 1 implying a more constructive relative ranking within the category, a 2 indicating a midrange ranking within the category and a 3 indicating a less constructive ranking within the category.

State regulatory rankings distribution*



As of May 20, 2021.
* Graph is based on rankings of regulatory climate for energy utilities only.
AA = Above Average; A = Average; BA = Below Average
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

RRA attempts to maintain a "normal distribution" of the rankings, with the majority of the states classified in one of the three Average categories. The remaining states are then split relatively evenly between the Above Average and Below Average classifications, as seen in the accompanying chart that depicts the current ranking distribution.

For a more in-depth discussion of the factors RRA reviews as part of its ratings process, see the Overview of RRA rankings process section that begins on page 8.

Rankings changes

In the previous "State Regulatory Evaluations" report, which was released March 3, 2021, RRA made four ranking changes — the rankings of the Louisiana Public Service Commission and the New Orleans City Council were each lowered one notch, while the rankings of Maryland and Mississippi moved up one notch.

With the issuance of this update, RRA is again modifying the ranking of four jurisdictions.

Historically, RRA has viewed the **Arizona** regulatory environment as somewhat restrictive from an investor perspective. A recent court ruling upended decades of precedent of Arizona Corporation Commission, or ACC, rulemaking autonomy that was derived from the commission's status as a constitutionally created rather than a legislatively created entity. The court ruled that the authority of the state legislature can, in fact, supersede that of the ACC regarding certain non-ratemaking matters, adding a degree of uncertainty as the state addresses energy transition and regulatory reform issues. Recent enactment of legislation governing the appeals process for ACC decisions introduced yet another layer of uncertainty. In light of these developments and in order to maintain balance in the ranking system, RRA is lowering the ranking of Arizona regulation to Below Average/1 from Average/3.

RRA is raising the ranking of **Maryland** regulation to Average/3 from Below Average/1. This is the third upward change for Maryland in the last couple of years and reflects the continuation of more constructive trends including the adoption of a multiyear rate plan framework that incorporates forward-looking test periods and will in the future include performance-based ratemaking provisions, adoption of authorized equity returns that are above prevailing industry averages when established, the commission's adherence to its historical practice of using actual utility capital structures to set rates, the willingness of regulators to move to year-end rather than average valuations for safety and reliability expenditures and constructive treatment of COVID-19 costs.

In **Oklahoma**, legislation was recently enacted allowing the state's utilities to securitize, following issuance of a financing order by the Oklahoma Corporation Commission, the costs they incurred in connection with the severe February weather event. Costs eligible to be securitized include, but are not limited to, fuel, purchased power, and natural gas commodity costs, and fuel-related storage costs. In recognition of the financial flexibility the new law affords the utilities, RRA is raising its ranking of Oklahoma's energy regulatory climate from Average/3 to Average/2 at this time.

RRA is lowering the ranking of **Texas** regulation as it pertains to electric utilities, which are regulated by the Public Utility Commission of Texas, from Average/2 to Average/3. The downgrade reflects ongoing uncertainty with respect to the regulatory construct that will be in place within the Electric Reliability Council of Texas in the wake of power outages and price spikes during a severe weather event in February.

The ensuing controversy has already led to changes in the makeup of the ERCOT board and the resignation of all three members of the PUC. Two new members have been appointed and confirmed, but a vacancy remains unfilled as the end of the legislative session approaches. It is unclear whether Gov. Greg Abbott will appoint a third commissioner prior to adjournment or whether, despite the ongoing controversy, he will appoint someone after the session ends, who would then be permitted to serve until the end of the next legislative session, which will not convene until 2023.

Against this backdrop, the legislature is considering bills that would expand the commission membership to five and change the selection process and qualifications for new commissioners going forward. Measures are also being considered to change the pricing mechanisms within ERCOT, even as the PUC refused to reprice power sold during the height of the emergency. Bills are also pending that would require more stringent weatherization practices and address recovery of excessive supply costs that impacted the vertically integrated utilities outside of ERCOT.

In addition, the PUC has opened a series of proceedings to address various aspects and implications of the weather-related events. See the Texas section of the report entitled "RRA Report Major utility cases in progress — Pending significant non-rate case activity" for further information.

RRA state regulatory evaluations

State-by-state listing — energy

Jurisdiction	Ranking	Jurisdiction	Ranking	Jurisdiction	Ranking
Alabama	Above Average/1	Louisiana—NOCC	Average/3	Ohio	Average/3
Alaska	Below Average/1	Louisiana—PSC	Average/2	Oklahoma*	Average/2
Arizona**	Below Average/1	Maine	Average/3	Oregon	Average/2
Arkansas	Average/1	Maryland*	Average/3	Pennsylvania	Above Average/2
California	Average/2	Massachusetts	Average/2	Rhode Island	Average/2
Colorado	Average/1	Michigan	Above Average/3	South Carolina	Average/3
Connecticut	Average/3	Minnesota	Average/2	South Dakota	Average/2
Delaware	Average/3	Mississippi	Average/1	Tennessee	Above Average/3
District of Columbia	Below Average/2	Missouri	Average/3	Texas—PUC**	Average/3
Florida	Above Average/2	Montana	Below Average/1	Texas—RRC	Average/2
Georgia	Above Average/2	Nebraska	Average/1	Utah	Average/2
Hawaii	Average/2	Nevada	Average/2	Vermont	Average/3
Idaho	Average/2	New Hampshire	Average/3	Virginia	Average/1
Illinois	Average/2	New Jersey	Below Average/1	Washington	Average/3
Indiana	Average/1	New Mexico	Below Average/2	West Virginia	Below Average/2
Iowa	Above Average/3	New York	Average/2	Wisconsin	Above Average/2
Kansas	Below Average/1	North Carolina	Average/1	Wyoming	Average/2
Kentucky	Average/1	North Dakota	Average/1		

As of May 20, 2021.
NOCC = New Orleans City Council; PSC = Public Service Commission;
PUC = Public Utility Commission; RRC = Railroad Commission
* Ranking raised since March 1, 2021
**Ranking lowered since March 1, 2021.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Issues to watch

February 2021 — Midwest cold snap

While the impacts in Texas were the most dramatic, the February event had widespread impacts across the midwestern U.S., and regulators in several other jurisdictions have ongoing investigations into the related issues. Jurisdictions where this is true include Colorado, Kansas, Minnesota, Nebraska, Oklahoma, South Dakota and the Railroad Commission of Texas, which oversees gas local distribution companies.

Coronavirus/COVID-19

In addition, COVID-19 pandemic-related issues continue to create regulatory overhang for U.S. utilities.

Moratoriums on utility service terminations were implemented in March and April 2020 by utilities in each of the 53 state-level jurisdictions followed by RRA. In some instances, the moratoriums were mandatory, in others voluntary and in others it has swung back and forth between the two.

As of May 15, 2021, the moratoriums had expired for all customers in 37 of these jurisdictions. In 10 jurisdictions moratoriums are in place with specified end dates that range from May 31 to as late as July 4, 2022.

In five states moratoriums remain in place for some customers but have expired for others. In one jurisdiction, the Texas PUC, a moratorium is in place with no specific end date. However, the moratorium is actually related to the February weather-related emergency, rather than COVID-19 per se. Certain providers have petitioned the commission to end the moratorium.

Since RRA's most recent update on COVID-19 regulatory action, the status of several states has changed.

In **Arizona**, the COVID-19 pandemic-related moratorium has expired, but the Arizona Corporation Commission is considering rules under which shutoffs would be prohibited between June 1 and Oct. 15 each year or on any day where temperatures were expected to be above 95 degrees Fahrenheit or below 32 degrees Fahrenheit.

The moratorium in the **District of Columbia** was to expire April 15, but rules adopted by the PSC in March require utilities to provide customers 45 days' notice before terminating service for nonpayment; such notice may not be sent until after the state of emergency is lifted. The public health emergency has been extended to May 20; therefore, the earliest disconnections could begin would be July 4.

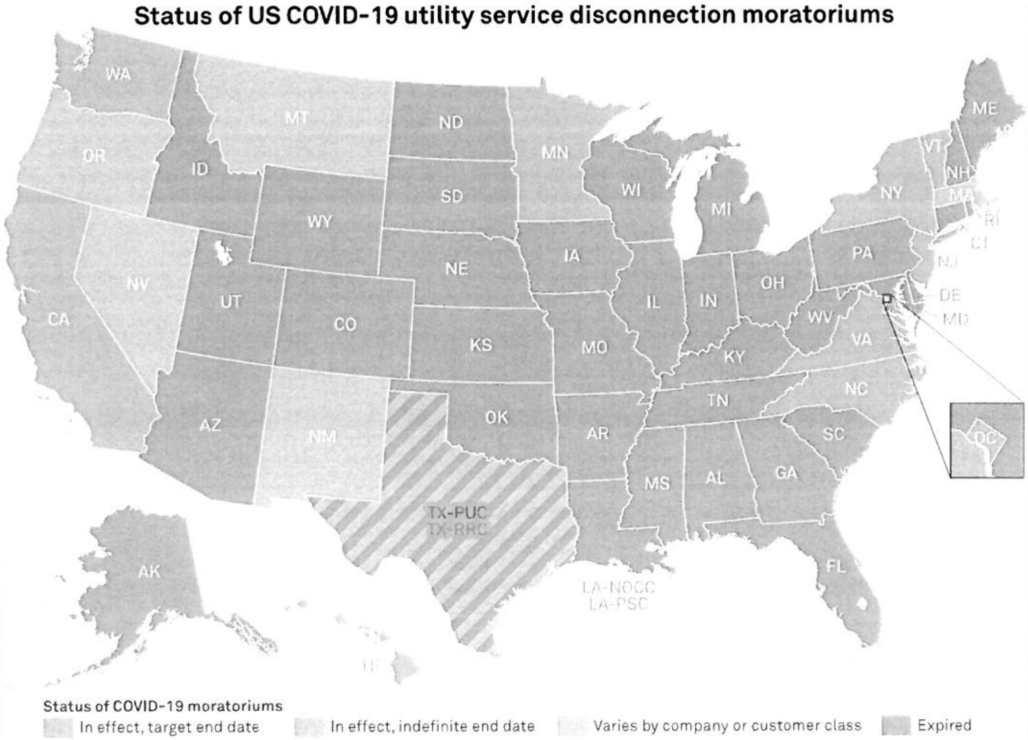
In **Maine**, the COVID-19 moratorium expired April 15.

Minnesota's moratorium was set to expire April 15 as well, but the PUC voted to extend the moratorium through Aug. 2.

In **New Mexico**, the moratorium expired for small utilities on May 4 but is to remain in place for large utilities until Aug. 1.

New York Gov. Mario Cuomo on May 11 signed legislation under which the moratorium on residential and small customer utility service disconnections is to be extended for a period of 180 days after either the COVID-19 state of emergency is lifted or 180 days after Dec. 31, 2021, whichever is earlier. As a result, the latest the moratorium would apply would be July 1, 2022.

Status of US COVID-19 utility service disconnection moratoriums



Data compiled May 15, 2021.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission
Map credit: Ciaralou Agpalo Palicpic
Sources: Regulatory Research Associates, a group within S&P Global Market Intelligence;
National Association of Utility Regulatory Commissioners; company websites

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In **Ohio**, the state's annual winter ban on shutoffs expired April 15.

In **Rhode Island**, the COVID-19 shutoff moratorium expired April 15, but pending legislation would bar utility service disconnections during a declared state of emergency.

Wisconsin's ban on shutoffs expired April 15; on March 22, the PSC had voted against extending it further.

When it comes to recovery of the related costs, some states have adopted a generic policy while others have taken a company-specific approach. In 34 jurisdictions, at least one utility has been authorized to defer costs related to COVID-19, which may or may not include lost revenue. Recovery of the deferred balances will be addressed in future rate proceedings, subject to a prudence review.

While these deferrals mute the impact of pandemic-related costs on utility earnings, the longer the moratoriums remain in place, the larger these deferred balances will grow, and the more problematic achieving cost recovery will become.

States to watch

In addition to the ranking changes and COVID-19 and weather impacts noted above, there are several jurisdictions where ongoing issues could signal a shift in the level of regulatory risk for investors.

A continuing myriad of negative developments stemming from the fallout from the responses of the state's electric utilities to Tropical Storm Isaias continue to warrant a watchful eye on the **Connecticut** regulatory environment. As a result of storm response deficiencies, the Connecticut Public Utilities Regulatory Authority, or PURA, indicated that a 90-basis-point reduction to the allowed ROE of Eversource subsidiary Connecticut Light and Power and a 10-basis-point reduction to the allowed ROE of Avangrid Inc. subsidiary United Illuminating will be imposed indefinitely in "any pending or future rate proceeding." In addition, the PURA proposed civil penalties against the utilities for their storm failures.

Also, as a result of storm response, regulatory reform legislation was enacted in October 2020 that requires the implementation of performance-based regulation for the electric distribution companies, addresses executive and incentive compensation, extends existing statutory deadlines for the PURA to adjudicate rate cases and render decisions on merger and financing applications, and outlines storm response penalties and ratepayer restitution. In accordance with the law, the PURA is investigating the appropriateness of decreasing rates on an interim basis for the state's electric distribution companies. The team will be monitoring and assessing the implications for utility investors.

In the **District of Columbia**, a decision is awaited on Exelon Corp. subsidiary Potomac Electric Power Co.'s first proposed multiyear rate plan. Intervenors to the case have called for the commission to reject the proposal and instead issue a decision based on a traditional test year filing. A final order is expected in the first half of 2021.

Illinois bears watching as the legislature considers a bill introduced in February that would extend the existing electric formula rate plan in place for Exelon Corp. subsidiary Commonwealth Edison Co. and Ameren Corp. subsidiary Ameren Illinois through 2032 and require the gas utilities to be subject to it as well. In addition, the measure calls for replacing the U.S. Treasury-yield-linked ROE formula with a formula based on a "national average" ROE.

In **Kansas** and **Missouri**, Evergy Inc.'s recent decision to change its business model on a stand-alone basis rather than pursuing a merger partner is the subject of ongoing review by regulators.

RRA state regulatory evaluations — energy

Above average/1	Above average/2	Above average/3	Average/1	Average/2	Average/3	Below average/1	Below average/2	Below average/3
Alabama	Florida	Iowa	Arkansas	California	Connecticut	Alaska	New Mexico	Dist. of Columbia
	Georgia	Michigan	Colorado	Hawaii	Delaware	Arizona	West Virginia	
	Pennsylvania	Mississippi	Indiana	Idaho	Louisiana — NOCC	Kansas		
	Wisconsin	Tennessee	Kentucky	Illinois	Maine	Montana		
			Nebraska	Louisiana — PSC	Missouri	New Jersey		
			North Carolina	Massachusetts	New Hampshire			
			North Dakota	Minnesota	Ohio			
			Virginia	Nevada	Oklahoma			
				New York	South Carolina			
				Oklahoma	Vermont			
				Oregon	Texas PUC			
				Rhode Island	Washington			
				South Dakota				
				Texas—PUC				
				Utah				
				Wyoming				

As of May 20, 2021.
NOCC = New Orleans City Council; PUC = Public Utility Commission; RRC = Railroad Commission
*Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

RRA also continues to closely monitor developments in **New York**. There are some changes forthcoming at the PSC in 2021. With the departure of John Rhodes, Gov. Andrew Cuomo, a Democrat, designated Commissioner John Howard as interim chair of the PSC. Commissioner James Alesi, a Republican, continues to serve pending reappointment or replacement. In addition, with energy transition issues at the forefront and numerous expanded regulated responsibilities, the PSC, as permitted under state law, adopted a resolution requesting that the governor expand PSC membership from five to seven. Cuomo has yet to act on the resolution as well as fill the vacancy created by Rhodes' departure. Legislation has also been passed that, if enacted, would require that the five-member PSC have at least one commissioner with consumer advocacy experience.

In **Virginia**, Dominion Energy Inc. subsidiary Virginia Electric and Power's, or VEPCO's, periodic earnings review proceeding got underway in March. This is the first "base rate case" for VEPCO in several years and will include a look-back at earnings in the calendar-years 2017, 2018, 2019 and 2020 for the company's legacy electric distribution and generation assets. A similar review for American Electric Power subsidiary Appalachian Power was completed in 2020, and the proceeding was relatively controversial.

Other jurisdictions that bear watching include the state of **Washington**. Legislation enacted in early May directs the Washington Utilities and Transportation Commission, or WUTC, to open a proceeding to investigate alternatives to traditional cost-of-service ratemaking that may include performance measures or goals, targets, performance incentives, and penalty mechanisms. The WUTC is to conduct the proceeding in conjunction with the state's utilities, the Washington attorney general's office and other stakeholders and to provide an update on the process to state legislators by Jan. 1, 2022.

*For a complete listing of RRA's in-depth reports, see the **Energy Research Library.***

For further insight on individual state regulatory practices and policies, refer to the Commission Profiles.

Overview of RRA rankings process

RRA maintains three principal rating categories, Above Average, Average and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint and Below Average indicating a less constructive, higher-risk regulatory climate. Within each principal rating categories, the numbers 1, 2 and 3 indicate relative position. The designation 1 indicates a stronger or more constructive rating from an investor viewpoint; 2, a midrange rating; and 3, a less constructive rating. Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."

Methodology

While numerical scores are employed, the rankings are subjective and are intended to be comparative in nature. RRA endeavors to maintain an approximate normal distribution with an approximately equal number of rankings above and below the average.

The rankings are designed to reflect the interest of both equity and fixed-income investors across more than 30 individual metrics. The individual scores are assigned based on the covering analysts' subjective judgement. The scores are then aggregated to create a single score for each state, with certain categories weighted more heavily than others.

The states are then ranked from lowest to highest and distributed among the nine categories to create an approximate normal distribution. This distribution is then reviewed by the team as a whole, and individual state rankings may be adjusted based on the covering analysts' recommendations, subject to review by a designated panel of senior analysts.

The variables that RRA considers in determining each state's ranking are largely the broad issues addressed in our State Regulatory Reviews/Commission Profiles and those that arise in the context of rate cases and are discussed in RRA Rate Case Final Reports.

The rankings not only reflect the decisions rendered by the state regulatory commission, but also reflect the impact of the actions taken by the governor, the legislature, the courts and consumer advocacy groups. The policies examined pertain largely to rate cases and the ratemaking process, but issues such as industry restructuring, corporate governance, treatment of proposed mergers and the ongoing energy transition are also considered.

Please note: In the charts within this report that show the rankings by category, the jurisdictions in each category are listed in alphabetical order rather than by relative position within the category.

The summaries below provide an overview of the variables RRA looks at, including a brief discussion of how each can impact the ranking of a given regulatory environment.

Governor/Mayor

The impact the governor, or in the District of Columbia the mayor, may have depends largely on the individual; the issue of elected versus appointed commissioners is evaluated separately.

RRA takes no view on which political party is the more or less constructive option. However, attributes of the governor or the gubernatorial election process that can move the needle here are: whether energy issues were a topic of debate in recent elections and what the tone/topic of the debate was, whether the governor seeks to involve himself or herself in the regulatory process, and what type of influence the governor is seeking to exert.

Commissioner selection process/membership

RRA looks at how commissioners are selected in each state. All else being equal, RRA attributes a greater level of investor risk to states in which commissioners are elected rather than appointed. Generally, energy regulatory issues are less politicized when they are not subject to debate in the context of an election.

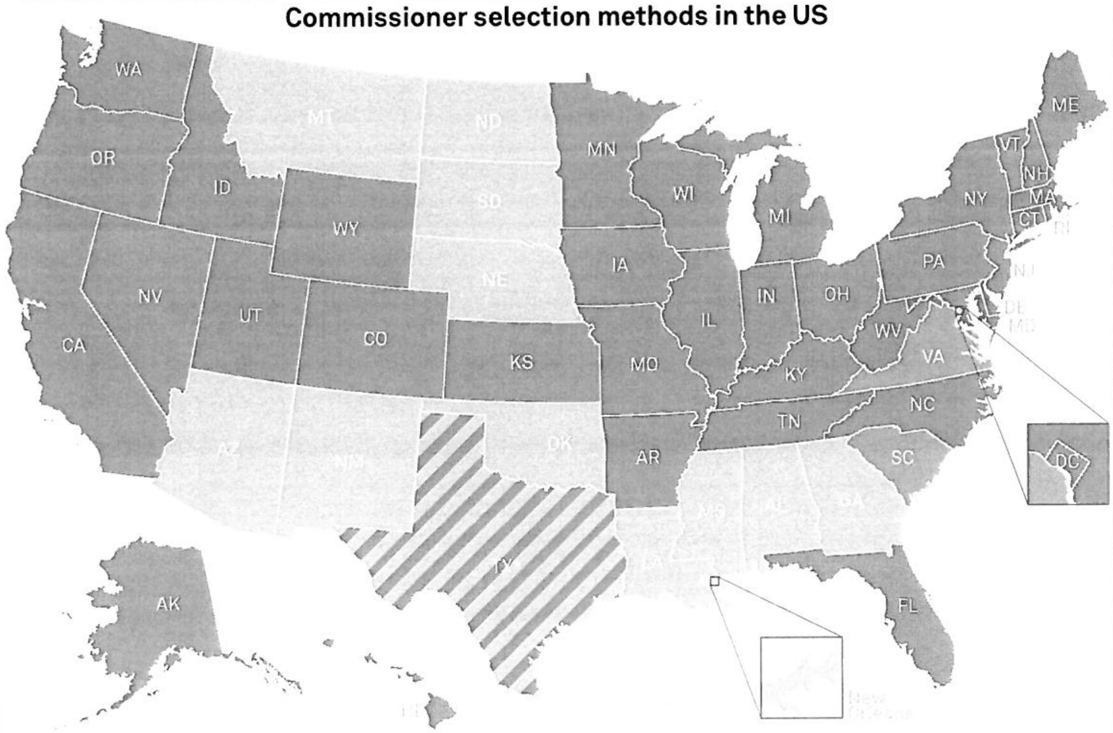
Realistically, a commissioner candidate who indicates support for the utilities and their shareholders or appears to be amenable to rate increases is not likely to be popular with the voting public. In addition, there might not be specific experience requirements to run for commissioner; so, a newly elected candidate may have a steeper learning curve with respect to utility regulatory and financial issues, which could make discerning what decisions that individual might make more difficult and could increase uncertainty.

However, there have been some notable instances in which energy issues played a key role in gubernatorial/senatorial elections in states where commissioners are appointed, with detrimental consequences for the utilities, e.g., Illinois, Florida, Maryland and more recently New York, all of which were downgraded by RRA at the time in order to reflect the increased risk associated with increased political scrutiny of the regulatory process and policies within the jurisdiction.

In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator.

In some instances, new commissioners have very little experience or exposure to utility issues, and in some respects, these individuals represent the highest level of risk, simply because there is no way to foresee what they will do or how long it will take them to "get up to speed." Controversy or "scandal" surrounding an individual and/or the potential for a conflict of interest are also red flags.

Commissioner selection methods in the US



Appointed | Direct voter elections; elected by district | Elected by General Assembly | Other

Data as of May 15, 2021.
* The Public Utility Commission of Texas members are appointed by the governor, while members of the Railroad Commission of Texas are elected in statewide elections
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

S&P Global
Market Intelligence

Similarly, a high rate of turnover or the tendency to allow vacancies to stand unfilled for a long period of time add to the level of regulatory risk in RRA's view.

Note: While commissioners currently serving in New Mexico were elected from each of five geographic districts, pursuant to a 2020 ballot measure, beginning in 2023 there will be only three members on the New Mexico Public Regulation Commission, and they will be appointed by the governor.

For additional information concerning the selection process in each state and the makeup of the commissions, refer to the RRA Regulatory Focus Topical Special Report entitled The Commissioners.

Commission staff/consumer interest

Most commissions have a staff that participates in rate proceedings. In some jurisdictions the staff has a responsibility to represent the consumer interest, and in others, the staff's statutory role is less defined. In addition, there may or may not be: additional state-level organizations that are charged with representing the interests of a certain class or classes of customers, such as the Attorney General or the Consumer Advocate; private consortia or lobbying groups that represent certain customer groups; and/or large-volume commercial and industrial customers that intervene directly in rate cases.

Generally speaking, the greater the number of consumer intervenors, the greater the level of uncertainty for investors. The level of risk for investors also depends on the caliber and influence of the intervening parties and the level of contentiousness in the rate case process. Even though a commission may not adopt an extreme position taken by an intervenor, the inclusion of an extreme position in the record for the case widens the range of possible outcomes, reducing certainty and increasing the risk of a negative outcome for investors. RRA's opinion on these issues is largely based on past experience and observations.

Settlements

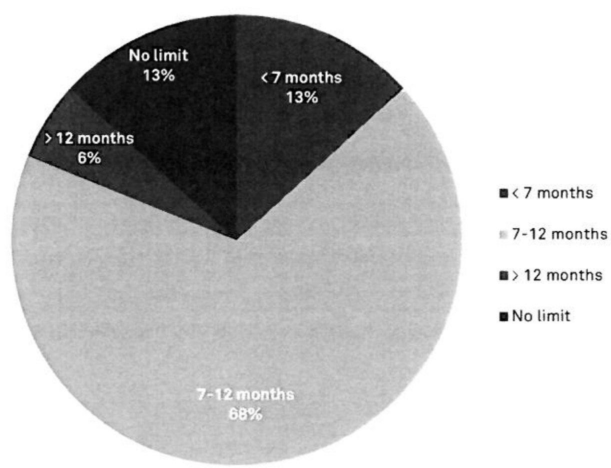
In most instances, the ability of the parties to reach agreement without having to go through a fully litigated proceeding is considered constructive, particularly since it reduces the likelihood of court review after the fact. However, RRA also endeavors to ascertain whether the settlements arise because of a truly collaborative approach among the parties, or if they result from concern by the companies that the commissioners' views may be more extreme than the intervenors', or that the intervenors will take a much more extreme position in a litigated framework than in a closed-door settlement negotiation, resulting in a less constructive outcome.

Rate case timing

For each state commission, RRA considers whether there is a set time frame within which a rate case must be decided, the length of any such statutory time frame and the degree to which the commission adheres to that time frame.

Generally speaking, RRA views a set time frame as preferable, as it provides a degree of certainty as to when any new revenue may begin to be collected.

Rate case time frame



Data gathered as of May 20, 2021.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

About two-thirds of state commissions nationwide have a rule or statute that requires a rate case to be decided within seven to 12 months of filing.

Shorter time frames may apply for limited-issue proceedings, but there are very few states where a rate case will take less than seven months to be decided.

In addition, a shorter time frame for a decision generally reduces the likelihood that the actual conditions during the first year the new rates will be in effect will vary markedly from the test period utilized to set new rates, thus keeping regulatory lag to a minimum.

Interim procedures

The ability to implement all or a portion of a proposed rate increase on an interim basis prior to a final decision in a rate case is viewed as constructive. However, should the commission approve a rate change that is markedly below the rates implemented on an interim basis, the utility would be required to refund any related over-collections, generally with interest.

In some instances, commission approval is required prior to the implementation of an interim increase and may or may not be easy to obtain, while in others, state law or commission rules permit the companies to implement interim rate increases as a matter of course. In some instances, the commission may establish a date prior to the final decision in the case that will be the effective date of the new rates. In these instances, the company may be permitted to recoup any revenue that was not collected between the effective date and the decision date.

Rate base

A commission's policies regarding rate base can also impact the ability of a utility to earn its authorized ROE. These policies are often outlined in state statutes, and the commission usually does not have much latitude with respect to these overall policies.

With regard to rate base, commissions are about evenly split between those that employ a year-end, or terminal, valuation and those that utilize an average valuation, with one using a "date certain." In some instances, the commission may employ a different rate base valuation method depending on the utility type or the type of case — general rate case or limited-issue proceeding — or based on the test year selected by the company.

Insert Rate Base Valuation Method Chart from RRA Evaluations Appendix Charts spreadsheet

In general, assuming rate bases are rising, i.e., new investment is outpacing depreciation, a year-end valuation is preferable from an investor viewpoint.

Again, this relates to how well the parameters used to set rates reflect actual conditions that will exist during the rate-effective period; hence, the more recent the valuation, the more likely it is to approximate the actual level of rate base being employed to serve customers once the new rates are placed into effect.

Some commissions permit post-test-year adjustments to rate base for "known and measurable" items, and, in general, this practice is beneficial to the utilities.

However, the rules with respect to what constitutes a known and measurable adjustment are not always specific, and there can be a good deal of controversy about what does and does not pass muster.

Another key consideration is whether state law and/or the commission generally permit the inclusion in rate base of construction work in progress, or CWIP, for a cash return. CWIP represents assets that are not yet, but ultimately will be, operational in serving customers.

Generally, investors view inclusion of CWIP in rate base for a cash return as constructive, since it helps to maintain cash flow metrics during a large construction cycle. Alternatively, the utilities accrue allowance for funds used during construction, which is essentially booking a return on the construction investment as a regulatory asset that is recoverable from ratepayers once the project in question becomes operational.

While this method bolsters earnings, it does not augment cash flow and does not support credit metrics. For a more in-depth look at rate base issues, refer to the RRA report entitled Rate base: How would you rate your knowledge of this utility industry fundamental?

Test period

With regard to test periods, there are a number of different practices employed, with the extremes being fully forecast at the time of filing, which is considered to be most constructive, on the one hand, and fully historical at the time of filing, considered to be least constructive, on the other.

Some states utilize a combination of the two, in which a utility is permitted to file a rate case that is based on data that is fully or partially forecast at the time of filing and is later updated to reflect actual data that becomes known during the course of the proceeding.

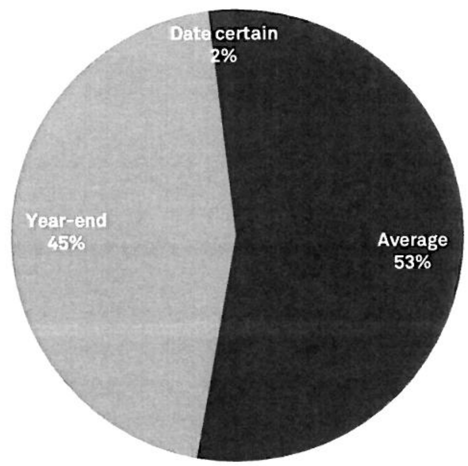
In these cases, the test year is historical by the time a decision is ultimately rendered, and so regulatory lag remains something of a problem.

In some states, the commission uses a historical test year for single-year base rate cases, but forward-looking test years for multiyear rate cases, alternative regulation plans and/or adjustment clauses.

Almost two-thirds of the 53 jurisdictions covered by RRA utilize a test year that is historical at the time of filing. As with rate base valuation, in some states, commissions use different test period types for different types of proceedings or for different utility types.

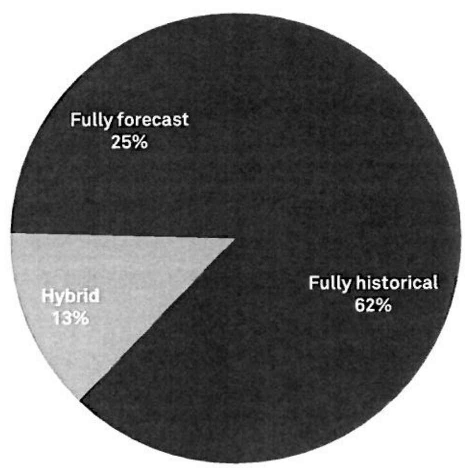
Many of the jurisdictions allow for known and measurable adjustments to the test year, but there is considerable variability regarding how far beyond the end of the test year these adjustments may go and statutes governing the definition of known and measurable can be ambiguous. Consequently, there can be wide disagreement among the rate case parties as to which adjustments qualify.

Rate base valuation method



Data gathered as of May 20, 2021.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Rate case test year



Data gathered as of May 20, 2021.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Return on equity

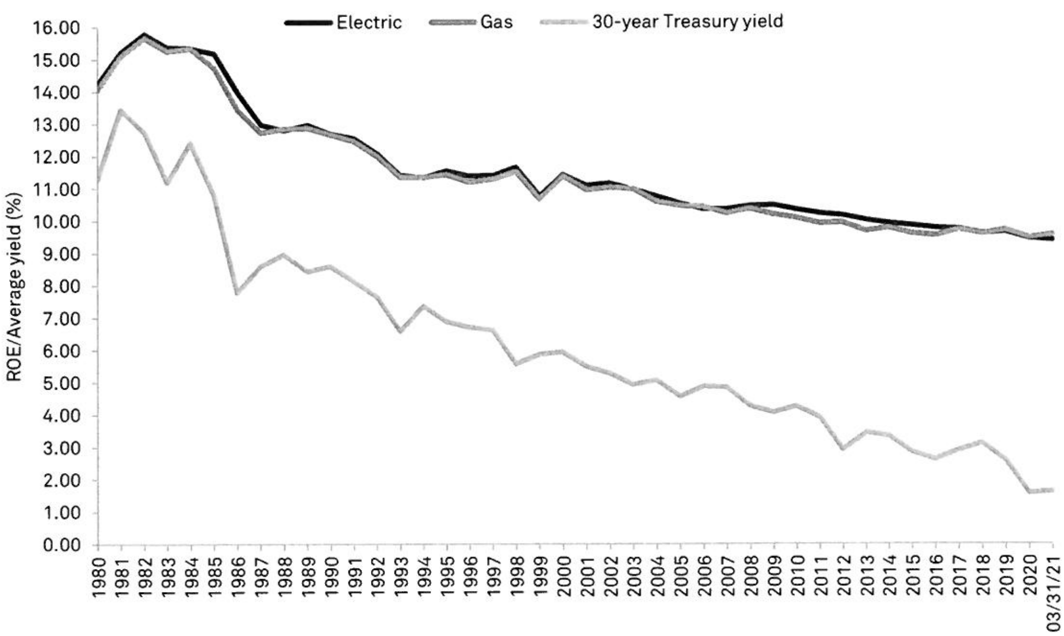
ROE is perhaps the single most litigated issue in any rate case. There are two ROE-related issues that RRA considers when evaluating an individual rate case and the overall regulatory environment: (1) how the authorized ROE(s) compares to the average of returns authorized for energy utilities nationwide over the 12 months or so immediately preceding the decision and (2) whether the company has been accorded a reasonable opportunity to earn the authorized return in the first year of the new rates.

In establishing rankings, RRA looks at the ROEs historically authorized utilities in a given state and compares them to utility industry averages, as calculated in RRA's Major Rate Case Decisions Quarterly Updates. When referring to these "averages," RRA means the average ROE approved in cases decided in a particular year; returns carried over from prior years are not included in the averages.

Authorized ROEs overall have been declining steadily since 1980, falling below 10% for the first time in 2011 for gas utilities and 2014 for electric utilities and remaining below that benchmark since.

Average authorized ROE in the US/30-year Treasury bond yields

Calendar years 1980-2020, 12 months ended March 31, 2021



Data compiled as of May 20, 2021.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Interest rates have been a key factor driving authorized ROEs downward, but commission determinations that various alternative or innovative ratemaking mechanisms have reduced risk for the companies and their investors across the board have played a role as well.

In 2020, with the U.S. economy challenged by fallout from the COVID-19 pandemic, the averages of the equity returns authorized for electric and gas utilities nationwide fell to their lowest levels on record.

The average ROE authorized electric utilities was 9.44% in all rate cases decided in 2020, below the 9.66% average in 2019. RRA recently reported that the average of the ROEs approved in the handful of electric rate cases decided in the first quarter of 2021 was 9.46% and the rolling average for the 12 months ended March 31, 2021, was 9.39%.

The average ROE authorized gas utilities in cases decided in 2020 was 9.46% versus the 9.71% average observed in 2019. ROEs approved in gas rate cases nationwide decided in the first quarter of 2021 averaged 9.71%, while the rolling 12-month average authorized was 9.56%.

Between 2015 and 2018, RRA had observed a modest recovery in authorized ROEs as the U.S. Federal Reserve unwound its quantitative easing policy and implemented a series of gradual interest rate increases.

As has typically been the case, authorized ROEs lagged interest rate trends somewhat and so continued to rise modestly during 2019 even though the Fed lowered interest rates to combat a slowing economy.

With more dramatic interest rate cuts implemented in the wake of the coronavirus pandemic, RRA's expectation is that the authorized ROEs will decline further.

The need to recognize the planned capital spending and other costs associated with the energy transition, the flat-to-modest sales growth absent the pandemic and the political distaste for approving rate increases when the country is in the middle of a crisis are shrinking "headroom" in utility rates.

Should tax increases enter the equation, not to mention things like the February 2021 Midwest weather event and the dislocation it caused in the Texas markets, as well as more frequent winter storms, all of which impose significant unplanned costs on the system, the pressure will be that much greater.

Since authorized returns are the area where regulators have the most room to employ subjective judgement, it stands to reason that authorized ROEs will be the mechanism regulators use to limit the level of resulting rate increases

In addition, consumer advocacy organizations continue to argue that lower returns on equity are warranted because of risk-reducing factors, such as limited-issue riders, decoupling mechanisms, alternative regulation constructs and changes to basic rate design.

This presents a stark contrast to views held by both fixed-income and equity investors that utilities are becoming more risky because of large capital spending plans, limited sales growth potential, changes in the structure of the industry and the regulatory framework occasioned by new technologies and the public policy shift favoring renewable resources, federal tax reform impacts, interest rate volatility and now the challenges being posed by overall market volatility as the coronavirus pandemic drags on.

Intuitively, authorized ROEs that meet or exceed the prevailing averages at the time established are viewed as more constructive than those that fall short of these averages.

However, in the context of a rate case, a utility may be authorized a relatively high ROE, but factors such as capital structure changes, the age or "staleness" of the test period, rate base and expense disallowances, the manner in which the commission chooses to calculate test year revenue, and other adjustments may render it unlikely that the company will earn the authorized return on a financial basis.

With respect to capital structure, most commissions utilize the company's actual capital structure at a given point in time, but in some instances the commission may rely on a hypothetical capital structure that represents a mix of debt and equity that the commission views as more reasonable or economically efficient. If the commission uses a capital structure that is more highly leveraged than the company's actual structure, this will lower the overall return authorized and the revenue requirement ultimately approved and may render it more difficult for the company to earn the authorized return on its actual equity.

Even if a utility is accorded a "reasonable opportunity" to earn its authorized ROE, there is no guarantee that the utility will do so. The revenue requirement and ROE established in a rate case are targets that the commission believes the established rates will allow the utility to attain.

Various factors such as weather, management efficiency, unexpected events, demographic shifts, fluctuations in economic activity and customer participation in energy conservation programs may cause revenue and earnings to vary from the targets set.

Hence, the overall decision may be restrictive from an investor viewpoint even though the authorized ROE is equal to or above the average. For a more detailed discussion of the rate case process, refer to the RRA report entitled *The Rate Case Process: A Conduit to Enlightenment*.

Accounting

RRA looks at whether a state commission has permitted unique or innovative accounting practices designed to bolster earnings. Such treatment may be approved in response to extraordinary events such as storms or for volatile expenses such as pension costs. Generally, such treatment involves deferral of expenditures that exceed the level of such costs reflected in base rates. In some instances, the commission may approve an accounting adjustment to temporarily bolster certain financial metrics during the construction of new generation capacity.

From time to time, commissions have approved frameworks under which companies were permitted to, at their own discretion, adjust depreciation in order to mitigate under-earnings or eliminate an overearnings situation without reducing rates. These types of practices are generally considered to be constructive from an investor viewpoint.

Federal tax law changes enacted in 2017 and effective in 2018, particularly the reduction in the corporate federal income tax rate to 21% from 35%, had sweeping impacts on utilities, with a flurry of ratemaking activity during 2018 and 2019. While the issues have been addressed for most of the RRA-covered companies, there are still some that have not.

For most of the companies that have already addressed the implications with regulators, rates have been reduced to reflect the ongoing impact of the lower tax rate, refunds to return to ratepayers related deferred over-collections are occurring over a relatively short time period, and amortization of the related excess accumulated deferred income tax liabilities is occurring over varying time periods — generally over the lives of the companies' assets for protected amounts and most often five to 10 years for unprotected amounts. RRA has been monitoring these developments and their impact on credit ratings and investor risk.

The prospect for tax rate changes under the Biden administration that would reverse, at least in part, the 2018 corporate income tax rate reduction raises the level of risk for all companies across the sector.

Another accounting-related issue that RRA has been following over the past year, is the treatment that is being according costs associated with the COVID-19 pandemic; specifically, whether the commissions have approved deferral of the costs, and how recovery of those deferrals is being or is to be addressed. This will become increasingly important as pandemic-related moratoriums are extended and deferred balances grow.

In the wake of the energy transition, increasing numbers of fossil generation facilities are being retired early, RRA is monitoring how commissions are treating these stranded costs — in some states the companies have been permitted to accelerate depreciation of the facilities in order to complete recovery of the investment prior to closure, and in others the utilities are being permitted to defer the remaining book value at closure, as a regulatory asset that is to be recovered over a period of years.

As the transition progresses, other classes of assets may become stranded, as well. So, this is an issue RRA will be monitoring on an ongoing basis.

Alternative regulation

Generally, RRA views as constructive the adoption of alternative regulation plans that are designed to streamline the regulatory process and cost recovery or allow utilities to augment earnings in some way. These plans can be broadly or narrowly focused. Narrowly focused plans may: allow a company or companies to retain a portion of cost savings relative to a base level of some expense type, e.g., fuel, purchased power, pension cost, etc.; permit a company to retain for shareholders a portion of off-system sales revenues; or provide a company an enhanced ROE for achieving operational performance and/or customer service metrics or for investing in certain types of projects, e.g., demand-side management programs, renewable resources, new traditional plant investment.

Overview of select alternative regulation plans in the US[1]

Formula-based ratemaking	Multi-year rate plans	Earnings sharing	Incentive ROEs	Electric fuel/ Gas costs	Capacity release/Off-system sales
Alabama	California	Alabama	Colorado	Indiana	Colorado
Arkansas	Connecticut	Arkansas	Iowa	Idaho	Delaware
Georgia	Dist. of Columbia[2]	Connecticut	Kansas[2]	Iowa	Florida
Hawaii	Florida	Florida	Mississippi	Illinois	Indiana
Illinois	Georgia	Georgia	Montana[2]	Kansas	Iowa
Louisiana—NOCC	Hawaii	Hawaii	Nevada	Kentucky	Kentucky
Louisiana—PSC	Louisiana—NOCC	Idaho	Ohio	Maryland	Louisiana
Maine	Maine	Iowa	Virginia	Missouri	Massachusetts
Massachusetts	Maryland	Kansas	Washington[2]	Montana	Missouri
Minnesota	Massachusetts	Louisiana—NOCC	Wisconsin	New Jersey	New Jersey
Mississippi	Minnesota	Louisiana—PSC		Oregon	New York
Pennsylvania	New Hampshire	Maine		Tennessee	North Dakota
Tennessee	New York	Massachusetts		Rhode Island	New Jersey
Texas—RRC	Ohio	Mississippi		Utah	Oklahoma
Vermont	Pennsylvania	Nevada		Vermont	Pennsylvania
	Rhode Island	New Mexico		Virginia	Rhode Island
	South Carolina	New York		Wyoming	South Dakota
	Utah	Oklahoma			Tennessee
	Vermont	Oregon			Texas—PUC
	Washington[2]	Rhode Island			Texas—RRC
	Wisconsin	South Dakota			Utah
		Vermont			
		Virginia			
		Washington			
		Wisconsin			

As of May 20, 2021.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility (ies) Commission; RRC = Railroad Commission.
[1]Mechanism in place for at least one utility in the state unless otherwise noted.
[2]Specifically permitted by rule, law or commission order; no mechanism currently in place.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

The use of plans with somewhat broader scopes, such as ROE-based earnings sharing plans, is, for the most part, considered to be constructive, but it depends upon the level of the ROE benchmarks specified in the plan and whether there is symmetrical sharing of earnings outside the specified range.

Some states employ even more broad-based plans, known as formula-based ratemaking. Formula-based ratemaking plans generally refer to frameworks where the commission established a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost of service base rate proceeding.

Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or period of years.

Others use multiyear rate plans, under which the commission approves a succession of rate changes that are designed to take into account anticipated changes in revenues, expenses and rate base. The commission may approve a static authorized ROE or the plan may provide for adjustments to the ROE during the plan's term. These plans often include true-up mechanisms to ensure that the company makes the investments it has committed to make at the inception of the plan. The plans often include earnings sharing mechanisms and may also include performance-based ratemaking provisions.

Court actions

This aspect of state regulation is particularly difficult to evaluate. Common sense would dictate that a court action that overturns restrictive commission rulings is a positive. However, the tendency for commission rulings to come before the courts and for extensive litigation as appeals go through several layers of court review may add an untenable degree of uncertainty to the regulatory process. Also, similar to commissioners, RRA looks at whether judges are appointed or elected, as political considerations are more likely to influence elected jurists.

Legislation

While RRA's Commission Profiles provide statistics regarding the makeup of each state legislature, RRA has not found a specific correlation between the quality of energy legislation enacted and which political party controls the legislature. Of course, in a situation where the governor and legislature are of the same political party, generally speaking, it is easier for the governor to implement key policy initiatives, which may or may not be focused on energy issues.

Key considerations with respect to legislation include: how proscriptive newly enacted laws are; whether the bill is clear or ambiguous and open to varied interpretations; whether it balances ratepayer and shareholder interests rather than merely "protecting" the consumer; and whether the legislation takes a long-term view or is a "knee-jerk" reaction to a specific set of circumstances.

Legislative activity impacting utility regulatory issues has been robust in recent years, as state policymakers, utilities and industry stakeholders seek to address "disruptors" that challenge the traditional regulatory framework. RRA follows these developments closely with an eye toward assessing whether the states are taking a balanced, sustainable approach and how legacy utility providers will be affected by the policies being adopted.

Corporate governance

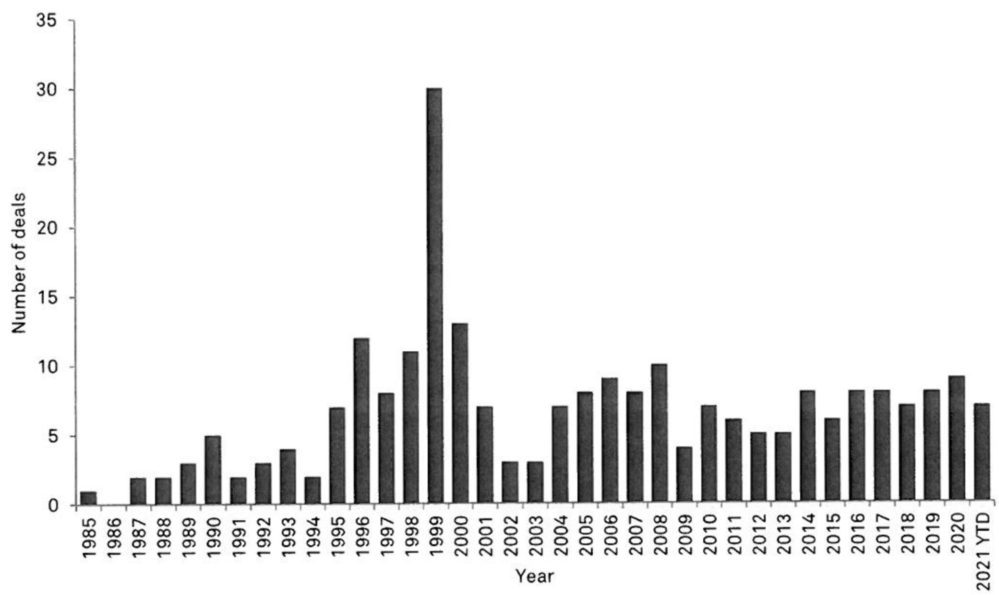
The term corporate governance generally refers to a commission's ability to intervene in a utility's financial decision-making process through required preapproval of all securities issuances, limitations on leverage in utility capital structures, dividend payout limitations, ring fencing and authority over mergers. Corporate governance may also include oversight of affiliate transactions.

In general, RRA views a modest level of corporate governance provisions to be the norm, and in some circumstances, these provisions, such as ring fencing, have protected utility investors as well as ratepayers. However, a degree of oversight that would allow the commission to "micromanage" the utility's operations and limit the company's financial flexibility would be viewed as restrictive.

Merger and acquisition activity

During the 1980s and early 1990s, there was not a lot of merger and acquisition activity in the sector. The years 1998 through 2000 saw a spike in activity, a lot of which centered around electric industry restructuring. After that, activity moderated but has remained fairly steady. Though merger and acquisition activity slowed during the first half of 2020 due to the COVID-19 pandemic, the pace picked up in the second half, and there were ultimately nine mergers announced, with an aggregate transaction value of about $34 billion. Thus far in 2021, seven deals have been announced that RRA is following, with an aggregate transaction value of roughly $40 billion.

Utility mergers and acquisitions announced 1985-2021 YTD



Data compiled as of May 20, 2021.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Aside from the involved entities' boards of directors and shareholders, deals involving regulated utilities must pass muster with some or all of a variety of federal and state regulatory bodies. The states generally look at the day-to-day issues such as the impact on rates, safety and reliability.

Looking more closely at the role of state regulators, 50 of the 53 non-federal jurisdictions RRA follows have some type of review authority over proposed mergers. In Indiana and Florida, preapproval by state regulators is not required before a transaction can proceed. In Texas, prior approval by the Public Utility Commission of Texas is required before a transaction involving an electric utility can take place, but Railroad Commission of Texas approval is not required for a transaction involving a local gas distribution company.

In evaluating a commission's stance on mergers, RRA looks at several broad issues such as whether there is a statutory time frame for consideration of a transaction and how long the process actually took.

For the 50 jurisdictions where commission preapproval is required, the review process and standards vary widely. In 20 of the jurisdictions, the commission must complete a merger review within a prescribed period of time, but in the remaining jurisdictions there is no timeline for their merger reviews, which means a commission could effectively "pocket veto" a transaction by delaying a decision until the merger agreement between the applicants expires or until pursuing the transaction is no longer feasible.

In addition, RRA considers whether a settlement was reached among the parties and, if so, whether the commission honored that settlement or required additional commitments. RRA also examines how politicized the process was: Did the governor, or in the District of Columbia the mayor, play a role? Did the transaction garner a lot of local media attention in the affected jurisdiction?

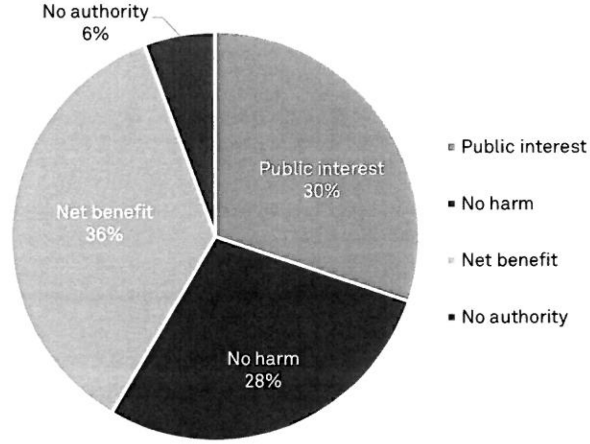
The definition of what constitutes a transaction that is subject to review can vary widely and may include sales of individual assets or a marginal minority interest as well as larger transactions where a controlling interest or the whole company is changing hands. State law often lacks specificity with respect to what constitutes a transaction that is subject to regulatory review.

In cases where the state commission has authority over mergers, RRA reviews the type of approval standard that is contained in state law and/or has been applied by in specific situations.

For discussion purposes, RRA groups the statutory standards into three general buckets: public interest, which is generally thought to be the least restrictive, no net ratepayer harm, which is somewhat more restrictive, and net ratepayer benefit, which is the most restrictive.

In many instances, regulators have broad discretion to interpret what the statutes may mean by these terms. So, the standard of review is often more readily apparent by looking at how prior transactions were addressed than by reading the statutory language — one commission's public interest might be another's net ratepayer benefit.

State commission merger review standards



Data compiled as of May 20, 2021.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

More narrowly, RRA reviews the conditions placed on the commission's approval of these transactions, including: whether the company will be permitted to retain a portion of any merger-related cost savings; if guaranteed rate reductions or credits are required that are or are not directly related to merger savings; whether certain assets were required to be divested; what type of local control and work force commitments are required; whether there are requirements for certain types of investment to further the state's public policy goals that may or may not be consistent with the companies' business models and whether the related costs will be recoverable from ratepayers; and whether the commission placed stringent limitations on capital structure and/or dividend policy or composition of the board of directors.

See the Merger activity section of each Commission Profile for additional detail on statutory guidelines for merger reviews and detail concerning approved/rejected mergers and the associated conditions.

Electric regulatory reform/industry restructuring

By electric industry restructuring, RRA means implementing a framework under which some or all **retail** customers have the opportunity to obtain their **generation** service from a competitive supplier. In a movement that began in the mid-1990s, about 20 jurisdictions have implemented retail competition for all or a portion of the customers in the utilities' service territories. The last of the transition periods ended as recently as 2011, when restructuring-related rate freezes concluded for certain Pennsylvania utilities.

RRA classifies each of the regulatory jurisdictions into one of three tiers based on their relative electric industry restructuring status.

Now that transition periods are completed, RRA has focused more on how standard-offer or default service is procured for customers who do not select an alternative provider and how much, if any, market-price risk the utility must absorb.

Electric industry restructuring in the US
Tier classifications

Tier 1	Power prices are competitively determined for all retail customers within the jurisdiction; both standard-offer-service and retail-access customers. Retail access is permitted for all customers. For the most part, the utilities in these jurisdictions do not own generation.
Tier 2	Retail access is permitted to at least some customers/customer classes. Competitively priced power is limited to retail access customers. Power prices for standard-offer-service customers remain regulated. For the most part, utilities remain vertically integrated.
Tier 3	Power prices are fully regulated for all retail customers. All retail customers must purchase their power from the franchised utility. Utiities are vertically integrated.

Data gathered as of May 20, 2021.
* In Texas, retail competition was implemented only within the ERCOT footprint, but within that footprint, power is competitively priced for all customers. Outside of ERCOT, power prices are regulated and the utilities are vertically integrated.
ERCOT = Electric Reliability Council of Texas Inc.
Map credit: Jose Miguel Fidel C. Javier
Source: Regulatory Research Associates, a group within S&P Global Market Intellgence

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However, initiatives are underway in Arizona and Virginia that could lead to an expansion of retail competition in those jurisdictions. In addition, in several states, initiatives are underway to revamp the way the transmission and distribution system is configured. These efforts have arisen from expansion of renewables and a focus on grid reliability/resiliency. RRA refers to this trend as electric industry restructuring phase two.

Similar to phase one, the recovery of stranded costs and ways to ensure universal service are real concerns. In phase two, the conversation is further complicated by the need to ensure not just the physical, but also the cybersecurity of the grid.

Several states got out in front of these issues and are addressing them in a broad-based way, while others are taking a more piecemeal approach dealing with deployment of advanced metering, distributed generation and net metering, time-of-use rates, cybersecurity and other issues on an individual basis.

The pressure to resolve these issues is increasing, as customers and policymakers want the changes in place yesterday. As these issues unfold, the same issues that were of concern in the first phase of restructuring will warrant close attention.

Gas regulatory reform/industry restructuring

Retail competition for gas supply is more widespread than is electric retail competition, and the transition was far less contentious as the magnitude of potential stranded asset costs was much smaller. Similar to electric retail competition, RRA generally does not view a state's decision to implement retail competition for gas service as either positive or negative from an investor viewpoint. RRA primarily considers the manner in which stranded costs were addressed and how default-service obligation-related costs are recovered.

Securitization

As it pertains to utilities, securitization refers to the issuance of bonds backed by a specific existing revenue stream that has been "guaranteed" by regulators and/or state legislators.

Securitization generally requires a utility to assign the designated revenue stream to a "bankruptcy remote" special-purpose entity or trust, which in turn issues bonds that will be serviced by the transferred revenue stream. The funds raised by the bond issuance flow to the utility, and in many cases are used to retire outstanding higher-cost debt and/or buy back common equity, thus lowering the company's weighted average cost of capital.

While it is unclear if securitization requires legislation, a specific legislative mandate generally improves the rating accorded the securitization bonds and lowers the associated cost of capital, given that a legislatively supported revenue stream may be more difficult to rescind than a stand-alone order of a state commission. In RRA's experience, no state commission has authorized securitization in the absence of enabling legislation.

Securitization is viewed as an attractive option because it allows regulators to minimize the customer rate impacts related to recovery of a particular utility asset. The carrying charge on the asset would be the lower interest rate applied to a highly rated, usually AAA, corporate bond rather than the utility's weighted-average cost of capital or even the interest rate on typical utility bonds, which are generally rated BBB and carry higher interest rates.

At the same time, securitization simultaneously reduces the investment risk for the utility by providing the utility up front recovery of its investment in what are usually non-revenue-producing assets. The company can then redeploy those investment dollars elsewhere.

The energy industry's introduction to asset securitization occurred in the mid-1990s, when legislation was enacted in certain states enabling utilities to securitize mandated conservation investments.

In the late 1990s and early 2000s, several states that implemented retail competition for electric generation enacted legislation allowing securitization to be used for recovery of uneconomic generating or other physical assets, above-market-priced purchased power contracts, regulatory assets, nuclear decommissioning costs, etc., that had the potential to become unrecoverable, or stranded, in a fully competitive market for generation supply.

In recent years, changing industry dynamics have once again begun to raise concerns about the prospects of stranded costs, and securitization is being used to address generation facilities that are retired prematurely.

Securitization has also been used as part of reorganization plans, to finance fuel/purchased power balances, distribution system improvements and extraordinary storm costs.

Adjustment clauses

Since the 1970s, adjustment clauses have been widely utilized to allow utilities to recover fuel and purchased power costs outside a general rate case, as these costs are generally subject to a high degree of variability. In some instances, a base amount is reflected in base rates, with the clause used to reflect variations from the base level, and in others, the entire annual fuel/purchased power cost amount is reflected in the clause.

Over time, the types of costs recovered through these mechanisms were expanded in some jurisdictions to include such items as pension and healthcare costs, demand-side management program costs, Federal Energy Regulatory Commission-approved regional transmission organization costs, new generation plant investment, and transmission and distribution infrastructure spending.

RRA generally views the use of these types of mechanisms as constructive but also looks at the frequency at which the adjustments occur, whether there is a true-up mechanism, whether adjustments are forward-looking in nature where applicable, whether a cash return on construction work in progress is permitted and whether there may be some ROE incentive for certain types of investment.

Another class of adjustment clauses known as revenue decoupling mechanisms allow utilities to adjust rates between rate cases to reflect fluctuations in revenues versus the level approved in the most recent base rate case that are caused by a variety of factors.

Some of these factors, such as weather, are beyond a utility's control, and the mechanism can work both ways — in other words it can allow the company to raise rates to recoup revenue losses associated with weather trends that reduce customer usage and can also require the company to reduce rates when weather trends cause usage to be higher than normal.

As energy efficiency initiatives have expanded, decoupling mechanisms have also been implemented to reduce the disincentive for utilities in pursuing energy conservation programs by making the utilities whole for reductions in sales volumes and revenues associated with customer participation in these programs.

Some of these mechanisms also allow the utility to adjust rates to reflect fluctuations in customer usage that are brought about by broader economic issues, such as demographic shifts, the migration of large commercial/industrial customers to other service areas, the shutdown of such businesses due to changes in their respective industries, recessions and, theoretically, crises such as the current COVID-19 pandemic.

RRA considers a decoupling mechanism that adjusts for all three of these factors to be a "full" decoupling mechanism and designates those that address only one or two of these factors as "partial" decoupling mechanisms.

Generally, an adjustment mechanism would be viewed as less constructive if there are provisions that limit the utility's ability to fully implement revenue requirement changes under certain circumstances, e.g., if the utility is earning in excess of its authorized return.

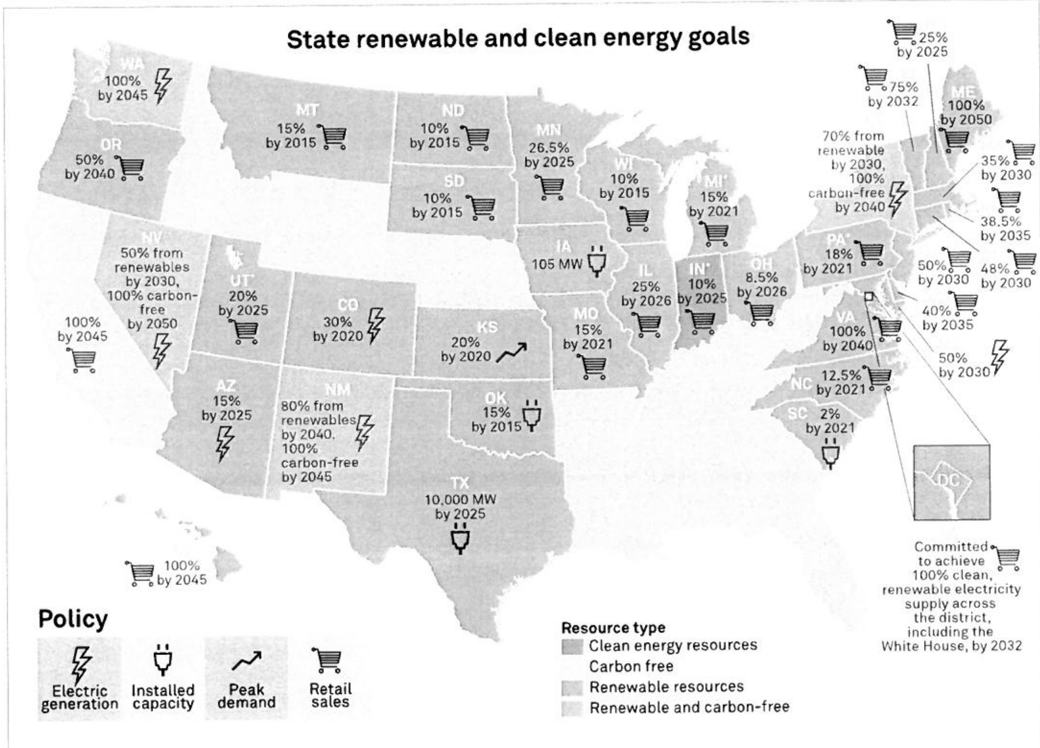
Integrated resource planning

RRA generally considers the existence of a resource-planning process to be constructive from an investor viewpoint as it may provide the utility at least some measure of protection from hindsight prudence reviews of its resource acquisition decisions. In some cases, the process may also provide for preapproval of the ratemaking parameters and/or a specific cost for the new facility. RRA views these types of provisions as constructive, as the utility can make more informed decisions as to whether it will proceed with a proposed project.

Renewable energy/emissions requirements

As with retail competition, RRA does not take a stand as to whether the implementation of renewable portfolio standards, or RPS, or an emissions reduction mandate is positive or negative from an investor viewpoint. However, RRA considers whether there is a defined preapproval and/or cost-recovery mechanism for investments in projects designed to comply with these standards.

RRA also reviews whether there is a mechanism such as a rate increase cap that ensures that meeting the standards does not impede the utility's ability to pursue other investments and/or recover increased costs related to other facets of its business. RRA also looks at whether incentives, such as an enhanced ROE, are available for these types of projects.



Data compiled April 12, 2021.
* Includes non-renewable alternative resources.
Indiana, Kansas, North Dakota, Oklahoma, South Carolina, South Dakota and Utah have renewable portfolio goals instead of standards.
In Minnesota, Xcel Energy is required to generate 31.5% of its retail sales from renewable resources by 2020.
Map credit: Ciaralou Agpalo Palicpic
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence
S&P Global Market Intelligence

In recent years, the focus on renewables has surged across the United States, with all but 12 jurisdictions developing some type of RPS. The proliferation of renewables, particularly those that are customer-sited or distributed resources, and the related rise of battery storage and electric vehicles have raised questions regarding the traditional centralized industry framework and whether that framework needs to change, perhaps ushering in a second phase of electric industry restructuring. How these changes are implemented is something RRA will be watching closely.

With respect to emissions, the threat of a federal carbon emissions standard for utilities and the spread of state-level initiatives have caused many companies to rethink legacy coal-fired generation, causing plants to be shut down earlier than anticipated. How the commissions address these "stranded costs" also poses a risk for investors and bears monitoring.

The zero-carbon movement has also caused utilities/states to reexamine investments in nuclear facilities and, in some cases, to develop programs designed to support the continued operation of those facilities even though they may not be economic from a competitive-markets standpoint. How these issues are addressed is something that RRA is also monitoring.

Rate structure

RRA looks at whether there are economic development or load-retention rate structures in place and, if so, how any associated revenue shortfall is recovered.

RRA also looks at whether there have been steps taken over recent years to reduce/eliminate interclass rate subsidies, i.e., to equalize rates of return across customer classes.

In addition, RRA considers whether the commission has adopted or moved toward a straight-fixed-variable rate design, under which a greater portion of a company's fixed costs are recovered through the fixed monthly customer charge, thus according the utility greater certainty of recovering its fixed costs.

This is increasingly important in an environment where weather patterns are more volatile, organic growth is limited due to the economy and the proliferation of energy efficiency/conservation programs, and large amounts of non-revenue-producing capital spending is required to upgrade and strengthen the grid.

Fixed vs. variable costs

Fixed	Variable
Depreciation	Gas commodity
Delivery O&M	Electric commodity
Property taxes	Generation O&M
Return on investment	
Customer service	

Data compiled as of May 20, 2021.
Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence.

In conjunction with the influx of renewables and distributed generation, the issue of how to compensate customer-owners for excess power they put back into the grid has become increasingly important and, in some instances, controversial. How these pricing arrangements, known as net metering, are structured can impact the ability of the utilities to recover their fixed distribution system costs and by extension their ability to earn their authorized returns.

***Contributors:** Brian Collins, Jim Davis, Russell Ernst, Lisa Fontanella, Monica Hlinka, Jason Lehman and Dan Lowrey.*

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RRA REGULATORY FOCUS

A look at storm cost recovery by energy utilities in Florida

Wednesday, September 4, 2019 1:11 PM ET

By Dan Lowrey
Market Intelligence

As Hurricane Dorian lashes Florida's East Coast on Sept. 4 as a Category 2 hurricane with winds in excess of 100 miles per hour, the state's utilities have been busy restoring minor outages, while thankful that a more direct hit did not occur.

The utility territory that had been square in Dorian's crosshairs was that of NextEra Energy Inc.'s Florida Power & Light Co., which was largely spared during the 2018 hurricane season but has a long history of grappling with such disasters. Duke Energy Florida LLC also reported outages from Dorian but escaped massive outages and damage caused by past hurricanes.

With catastrophe insurance for such major disasters generally unavailable to utilities, since Hurricane Andrew devastated the state in 1992, utilities have been self-insuring by accruing storm reserve accounts to pay for restoration costs. Any storm costs in excess of accrued reserves are then recovered through storm cost recovery proceedings before the Florida Public Service Commission.

Among storm-prone states, perhaps none has been as proactive in establishing mechanisms to allow utilities timely recovery of costs associated with responding to and repairing storm damage than the Sunshine State. Florida permits cost recovery through a rider/surcharge, allows utilities to fund reserve accounts on an ongoing basis to cover expenses and also allows utilities to securitize storm-damage restoration costs. For more detail on these policies, refer to the Florida state commission profile.

In 2006, the PSC authorized Florida Power & Light to issue $708 million of 12-year bonds to securitize 2004 and 2005 hurricane restoration costs and to rebuild its storm damage reserve. The PSC authorized the company to recover $198.7 million of 2004 restoration costs and $735.6 million of 2005 restoration costs and to rebuild its storm damage reserve to $200 million. To date, no other utilities have availed themselves of the securitization option. Securitization is a mechanism created by a state legislature that allows a utility to issue bonds through a bankruptcy remote special purpose entity, with a guaranteed revenue stream to service the bonds. This paves the way for lower financing costs that reduce the overall cost to customers for restoration costs.

In addition to Florida, Texas, Mississippi, Louisiana and the City of New Orleans, all Gulf Coast jurisdictions that historically have seen robust hurricane activity, are among the most proactive with respect to dealing with storm-related cost recovery and funding.

While 2014 and 2015 were relatively quiet in terms of hurricane activity impacting Florida utilities, the years of 2016-2018 have witnessed an increase in damage claims with costs spiking in 2017 following the destruction wrought by Hurricane Irma, a Category 4 monster.

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Florida PSC authorized recoverable storm costs ($M)

Company	2018	2017	2016	2015	2014
Florida Power & Light Co.		1,253.5	294.8		
Tampa Electric Co.		91.3[1]			
Florida Public Utilities Co.		1.9[2]			
Duke Energy Florida LLC	223.5[3]	485.2			
Gulf Power Co.	342[3]				
Peoples Gas System	3.4[3]				
Total	**568.9**	**1,738.7**	**294.8**		

As of Aug. 30, 2019.
[1] Includes storm cost recovery 2015-2017
[2] Includes storm cost recovery 2016-2017
[3] Interim storm cost recovery surcharge approved, no final order issued.
Year indicates when event occurred leading to the storm response/restoration costs.
Amounts include net recoverable retail costs and amount to replenish storm reserve.
Restoration costs below $1 million excluded.
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

FPL was hardest hit by Irma, incurring total restoration costs of more than $1 billion. Hurricane Irma impacted all 35 counties and 27,000 square miles of FPL's service territory and caused more than 4.4 million customers to lose power. The PSC on Aug. 1 issued a final order approving a settlement and granting FPL recovery of total storm restoration costs of about $1.25 billion. However, the settlement provided for the offset of such costs with savings from the 2018 reduction in the corporate income tax rate to 21% from 35%.

Similar treatment was accorded to other utilities in the state. Duke Energy Florida, or DEF, and Tampa Electric Co., entered into settlements to use savings related to tax reform to cover restoration costs for recent hurricanes, including Irma, Matthew, Nate and Hermine as well as various tropical storms impacting their territories between 2015 and 2017. The PSC voted in May to approve the settlement agreements.

DEF also agreed to apply federal tax savings to offset an interim storm restoration surcharge for Hurricane Michael, which hit Florida's panhandle in October 2018 as a Category 4 storm that caused widespread damage to DEF's Northwest Florida service area. Hurricane Michael made landfall near Mexico Beach, Fla., with winds as high as 155 mph, and was the most powerful storm to make landfall on the panhandle. At its height, approximately 77,000 DEF customers lost power as a result of the damage. DEF had originally requested approval to recover $223.5 million, equating to $6.95 on a monthly 1,000 kWh residential bill for 12 months, beginning in July. The proceeding remains open and a final order has not been issued by the PSC.

While the PSC has addressed recovery for storms costs incurred in 2017 and earlier, several proceedings remain outstanding with respect to 2018 storm costs. In addition to the DEF proceeding noted above, the PSC has approved interim storm cost recovery surcharges Gulf Power Co. and Peoples Gas System for costs incurred in connection with Hurricane Michael. Final orders have not been issued in those proceedings.

The PSC approved Gulf's request for an interim storm restoration recovery charge of $8.00 on a monthly 1,000 kWh residential bill, effective with the first billing cycle for July. Gulf estimates that the proposed recovery charge will need to be in effect for about 60 months. Peoples' residential bill for a customer using 12.8 therms of gas will reflect a 76-cent surcharge beginning in August and ending in December, under the approved surcharge.

A broken distribution pole and transformer in Cocoa Beach, Fla., in a Sept. 14, 2017 photo. Source: Florida Power & Light Co.

Utilities incur a variety of costs responding to and restoring service after storms. Costs by major category, include line clearing, vehicle and fuel, materials and supplies, logistics, regular and overtime payroll, contractor costs and property damage for storm charges that have been invoiced and processed by the company. Third-party reimbursements are excluded from recovery. For example, after Hurricane Irma, AT&T Inc. reimbursed FPL about $2.4 million for 878 net poles replaced by FPL on its behalf.

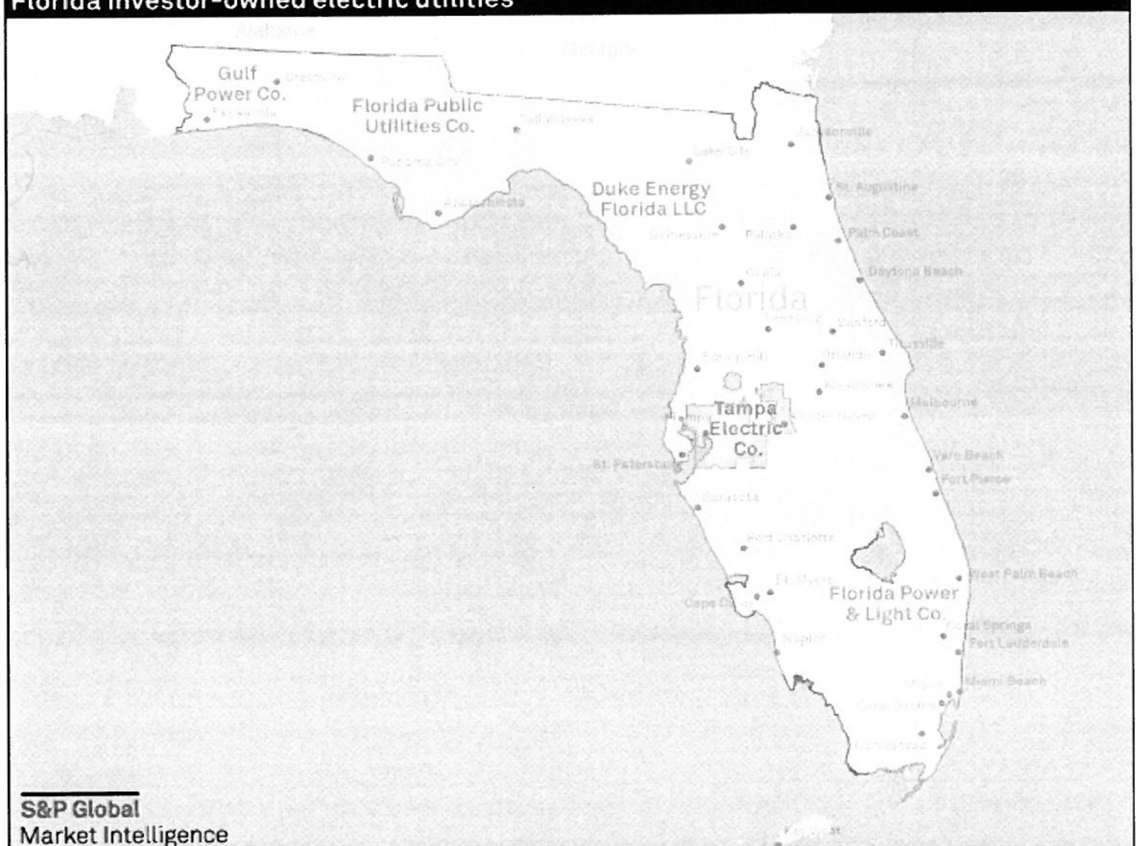
Under the state's Incremental Cost and Capitalization Approach for accounting for recoverable storm restoration costs, costs charged to cover storm-related damages shall exclude those costs that normally be charged to noncost recovery clause operating expenses in the absence of a storm. In addition, capital expenditures for the removal, retirement and replacement of damaged facilities charged to cover storm-related damages shall exclude the normal cost for the removal, retirement and replacement of such facilities in the absence of a storm.

Cost recovery proceedings differ for storm "hardening," which has been the focus of legislative efforts to prepare the state grid for the worst Mother Nature has to offer. Among states, Florida has adopted arguably the most comprehensive program for hardening infrastructure from storm damage. Currently, Florida's five investor-owned utilities file storm hardening plans with the PSC that must be updated every three years. The PSC began requiring the three-year plans in 2006 after a brutal hurricane season. The latest plans for 2019-2021 for Florida's investor-owned utilities were approved by the PSC in July. The state is also looking to expedite cost recovery for storm-hardening activities.

In June, the PSC opened a rulemaking to implement legislation passed in the 2019 session that establishes a Storm Protection Plan Cost Recovery Clause, allowing utilities to seek more timely recovery of storm hardening investments outside a general rate case. The legislation requires utilities to submit to the PSC a 10-year plan explaining "the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." Such grid hardening activities include burying transmission lines and vegetation management.

With Dorian moving north, a landfall in the Carolinas is looking like a possibility. For a look into storm cost recovery in North Carolina, refer to: A case study in storm cost recovery – Duke Energy Progress and Hurricane Matthew.

Florida investor-owned electric utilities



Data as of Aug. 31, 2018.
Includes Regulatory Research Associates-covered companies.
Map credit: Ver Anthony Odevilas
Source: S&P Global Market Intelligence

RRA is a group within S&P Global Market Intelligence.

For a full listing of past and pending rate cases, rate case statistics and upcoming events, visit the S&P Global Market Intelligence Energy Research Home Page.

For a complete, searchable listing of RRA's in-depth research and analysis, please go to the S&P Global Market Intelligence Energy Research Library.

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MOODY'S
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RATING METHODOLOGY

Regulated Electric and Gas Utilities

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» *contacts continued on the last page*

This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.[1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

THIS METHODOLOGY WAS UPDATED ON THE DATES LISTED AS NOTED: ON FEBRUARY 22, 2019, WE AMENDED A REFERENCE TO A METHODOLOGY IN APPENDIX E AND REMOVED OUTDATED TEXT; ON AUGUST 2, 2018, WE MADE MINOR FORMATTING ADJUSTMENTS THROUGHOUT THE METHODOLOGY; ON FEBRUARY 15, 2018, WE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34; AND ON SEPTEMBER 27, 2017, WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

1 This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe
» A summary of the rating methodology
» A discussion of the key rating factors that drive ratings
» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

2 Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

3 Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

4 We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply dueto a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

5 A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest / Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

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

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

6 For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

7 Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$

8 In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

[9] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.
Ba	**B**	**Caa**	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	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	5.00% **	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	Definiitons
Market Position	5.00% *	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	5.00% **	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. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

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

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

10 In certain circumstances, analysts may also apply specific adjustments.

11 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	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	10.00%	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	7.50%	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%

Notching for Structural Subordination of Holding Companies

Why It Matters

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. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[13] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

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

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

12 The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to theHoldCo.

13 Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

14 While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

» Substantial diversity in cash flows from a variety of utility OpCos

» Meaningful dividends to HoldCo from unlevered utility OpCos

» Dependable, meaningful dividends to HoldCo from non-utility OpCos

» The group's investment program is primarily in strong utility businesses

» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing to stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma

15 See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based onlegislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary, or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures forsetting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not befully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

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

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

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. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

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

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%

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[16] 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

[16] 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. 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 the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

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 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 (e.g., many parts of Asia and Europe) 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. In the US, this 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 (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) 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 (for example, Unregulated Utilities and Power Companies).

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.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

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 been rated under the Regulated Networks methodology.

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.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Appendix E: 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.[17] 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. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

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 quite pervasive in the past two decades. 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. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. 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

17 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

18 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report,

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 follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling 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).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: 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 are 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 each particular circumstance may be treated differently by Moody's. 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 otherwise 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 Research

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

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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