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.

1399

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

1400

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 the HoldCo.

[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 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.

* 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

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Factor 4: Financial Strength

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

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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MOODY'S
INVESTORS SERVICE

Moody's INVESTORS SERVICE

CREDIT OPINION

3 April 2019

Update

Rate this Research

RATINGS

ALLETE, Inc.

Domicile	United States
Long Term Rating	Baa1
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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ALLETE, Inc.

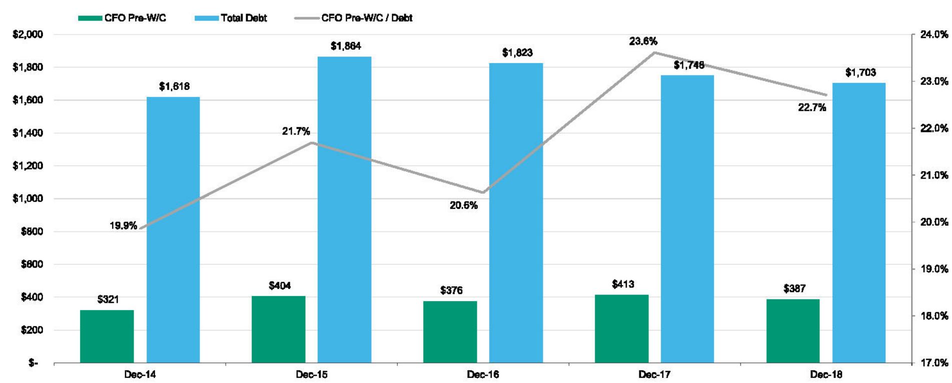
Update following downgrade

Summary

ALLETE's credit is underpinned by the largely stable and predictable cash flows associated with its regulated assets that account for about 85% of consolidated net income, the credit supportive nature of the rate making mechanisms available to its regulated companies. These positive attributes are partially offset by a relatively challenging rate case outcome and weaker debt coverage ratios. The company's credit quality is also tempered by its material exposure to commodity risk-exposed industrial customers. The company's credit also reflects our expectation that ALLETE's unregulated business will remain relatively small and will also produce stable and predictable cash flows.

Exhibit 1

Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($MM)



Source: Moody's Financial Metrics

Credit strengths

» Access to credit supportive ratemaking construct

» Plan to maintain cost competitive position while transforming generation mix

» Appropriate financial ratios for current credit profile

Credit challenges

» Credit negative rate case outcome

» Material exposure to commodity sensitive industrial customers

» Moderate exposure to carbon transition risk

Rating outlook

ALLETE's stable outlook reflects our expectation that its financial ratios will remain consistent and appropriate for its current credit profile, with cash flow from operations pre-working capital to debt remaining at or close to 20%. The stable outlook also factors in the company's focus on limiting the overall size and business risk of its unregulated segment.

Factors that could lead to an upgrade

» Although unlikely over the near term given recent regulatory and financial developments, ALLETE's rating could be raised if the Minnesota regulatory environment improves materially and the company achieves stronger than expected financial ratios such that it reports cash flow from operations pre-working capital to debt above 22%, on a sustained basis.

Factors that could lead to a downgrade

» ALLETE could be downgraded if there is a further decline in the credit supportiveness of the Minnesota regulatory framework. Given its elevated exposure to industrial customers, the company could also be downgraded if there is a substantial deterioration in U.S. macroeconomic conditions that resulted in a material and sustained drop in retail electricity volumes that are not offset by off-system sales or other means. A downgrade could also result from a further weakening of ALLETE's financial ratios, such that cash flow from operations pre-working capital to debt remains below 19% for a sustained period. A material increase in ALLETE's unregulated business segment or a marked increase in the business risk profile of the company's unregulated segment could place downward pressure on the company's rating as well.

Key indicators

Exhibit 2
ALLETE, Inc. [1]

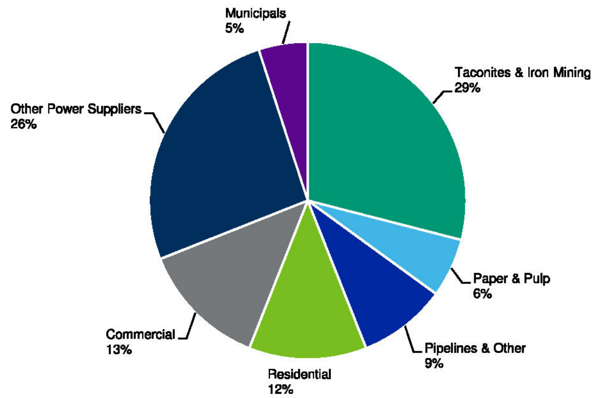
	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18
CFO Pre-W/C + Interest / Interest	6.2x	6.5x	5.8x	6.4x	6.0x
CFO Pre-W/C / Debt	19.9%	21.7%	20.6%	23.6%	22.7%
CFO Pre-W/C – Dividends / Debt	14.7%	16.4%	15.0%	17.4%	16.0%
Debt / Capitalization	43.3%	43.8%	42.8%	43.3%	41.8%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

ALLETE Inc. is a Duluth, MN based energy company. Its regulated operations represent about 85% of consolidated net income and consist of its operating utility division Minnesota Power (MP, not rated, rate base $2.6 billion), a wholly-owned regulated utility subsidiary Superior Water Light & Power (SWL&P, A3 stable, rate base $80 million), and an 8% ownership stake in American Transmission Company LLC (ATC, A2 stable). MP provides integrated electric services to around 145,000 retail customers. It also provides wholesale services to 16 municipalities in northeastern Minnesota and its Wisconsin based, sister utility company SWL&P. MP is heavily exposed to industrial customers, with 50% of its energy output being sold to industrial end-users in 2018. SWL&P is a small transmission and distribution utility company serving about 15,000 electric, 13,000 natural gas and 10,000 water customers in northwestern Wisconsin.

Exhibit 3
2018 Regulated Operations Revenue



Source: Company Data

Following the recent sale of its U.S. Water Services business, ALLETE's unregulated segment consists of contracted coal mining operations in North Dakota, ALLETE Clean Energy (ACE, not rated), a developer and owner of unregulated but long-term contracted renewable energy projects, and a small real estate investment segment.

Detailed credit considerations

CREDIT NEGATIVE GENERAL RATE CASE OUTCOME PARTIALLY OFFSETS SUPPORTIVE RATEMAKING MECHANISMS

ALLETE's credit is largely driven by the credit quality of its regulated vertically integrated utility business Minnesota Power (MP, not rated), that accounts for roughly 75% of consolidated net income.

MP is a Minnesota-based utility whose operations have access to above average ratemaking mechanisms including the application of a forward test year when setting rates, the ability to implement interim rates soon after filing for a general rate case, and access to multiple rider mechanisms. However, these credit positive ratemaking tools are mitigated by MP's latest general rate case outcome that points to a less supportive regulatory relationship between MP and the Minnesota Public Utilities Commission (MPUC).

On 30 January 2018, the Minnesota Public Utilities Commission (MPUC), MP's primary regulator, approved a $12.6 million rate increase for MP, 14 months after the company had filed its first general rate case since 2011. The MPUC's approved rate increase was materially lower than MP's original request of $55 million (subsequently revised to $39 million when a key industrial customer restarted operations). It is also significantly below the interim rate increase of $35 million that MP began collecting from customers in January 2017 (revised to $32 million as of 1 May 2017). The rate case outcome is credit negative for ALLETE because it results in a net reduction in customer rates versus the anticipated 6% net increase. These lower revenues place downward pressure on the company's debt coverage ratios.

The difference between MP's $39 million request and the MPUC's $12.6 million order is driven by both a lower approved equity return as well as expense disallowances. The MPUC lowered MP's allowed ROE to 9.25% from the requested 10.25%, below the national average of about 9.6% for 2017. The lower ROE represents about $20 million of the difference between MP's ask and the approved rate increase. The remaining difference relates to various expense disallowances including a decision to disallow the recovery of about $3 million of prepaid pension expenses. Although the amount is relatively small, it is noteworthy because Northern States Power Minnesota (A2 stable), the state's largest regulated utility, has received approval to recover such expenses in its rates. MP's inability to recover certain expenses already incurred has led the company to significantly cut costs to reduce its operating expenses in order to earn its allowed equity return without reducing costs elsewhere.

Another credit negative development resulting from MP's general rate case was the MPUC's ruling against the adoption of an annual rate review mechanism (ARRM) which was intended to mitigate the impact of MP's industrial customers idling their plants. Unlike peer utilities in the state with more balanced mix of customers, MP's industrial customers account for about half of its annual sales volume, and their vulnerability to broader economic cycles makes them inherently more volatile than residential customers. The ARRM would have provided an automatic ROE true-up that would have allowed MP to add a surcharge on customer bills if its earned ROE fell below a predetermined level or provide a refund if it was higher.

FINANCIAL RATIOS APPROPRIATE FOR CREDIT PROFILE

ALLETE's cash flow from operations pre-working capital to debt is expected to decline to roughly 20% on the heels of a less credit supportive general rate case outcome in 2018, the passage of Federal tax reform in late 2017, and the company's plans to significantly increase its capital expenditures in 2019 to $530 million, up from an average of roughly $275 million for the previous three years. Although capex is forecasted to decline from the 2019 high, the growth in the company's operating cash flow generation resulting from these investments will lag the growth of its debt balance, and result in weaker debt coverage ratios.

MATERIAL INDUSTRIAL CUSTOMER EXPOSURE ADDS VOLATILITY TO THE COMPANY'S BUSINESS RISK PROFILE

ALLETE's exposure to industrial customers is significant, representing roughly 50% of annual sales volume in most years, the highest within the Moody's US regulated utility universe. Its industrial customers consist of operating margin sensitive businesses such as iron pellet and taconite producers (69% of industrial KWh sold in 2018), paper, pulp and wood products companies (14%), and oil pipelines and other industrials (17%). All three industries faced challenging market environments that translated into weaker industrial sales in 2015 and 2016, but the trend reversed in 2017 with industrial customers returning to full production for most of the last two years, largely on account of tariffs imposed on steel imports.

The cyclicality of ALLETE's industrial customers' demand is a credit negative since these are the company's largest customers that account for 45% of consolidated revenues. In the absence of decoupling mechanisms, lower than anticipated regulated volumes can have a material negative impact on ALLETE's cash flow from operations. This was particularly apparent in 2009 when its taconite producer customers operated at 45% of capacity (procuring only 2.1 GWh of power). The impact on 2015 and 2016 operating cash flows is less obvious due to one time events such as the fee received for building a wind farm for a third party investor owned utility and increased off-system sales volumes.

ALLETE looked to mitigate the risk posed by lower industrial customer sales when it filed for the subsequently denied ARRM mechanism.

Still, going forward ALLETE will be able to offset some of the cash flow volatility associated with its industrial customers through the application of the legislatively approved Energy-Intensive Trade-Exposed (EITE) Customer Rates. Those are intended to be revenue neutral, however they shift some of MP's fixed cost recovery away from industrial customers to the more stable residential and commercial customers. The Minnesota's EITE customer ratemaking legislation was enacted in 2015, with the intent of providing competitive rates for certain industries such as mining and forest products.

PLAN TO MAINTAIN ITS COMPETITIVE COST POSITION

MP's material exposure to industrial customers that are particularly margin sensitive means it must maintain rates as low as possible in order for these customers to operate and avoid the risk of customer self-generation. The majority of its power requirements are currently generated through its coal-fired facilities (43% of 2018 MWh) and renewable power plants (15%). The balance of its energy needs are procured in MISO and other power suppliers (27%) and long-term power purchase agreements (PPAs) (15%).

ALLETE aims to maintain MP's cost competitive position in the future by reshaping its power supply from a predominantly coal-based energy mix to one where renewables, coal-fired and natural gas power each contribute about one third of the expected load requirement by 2025.

Following the completion of the Bison 4 wind farm in late 2014, MP owns 522 MW of highly economical wind capacity (average cost of less than 3ct/KWh for its North Dakota 497 MW Bison Wind Energy Center), and maintains two long-term PPAs totaling 98MW. MP intends to increase its access to renewables over time through two additional long-term PPAs with Manitoba Hydro for a total capacity of 383 MW set to start in 2020, and has received regulatory approval for a 250 MW wind PPA with Nobles 2, a 49/51 project jointly owned by ALLETE and Tenaska.

MP is also making progress with the transformation of its coal generation fleet. The company completed the required environmental upgrades at its Boswell Unit 4 (468 MW) in 2015, and idled its two Taconite Harbor units (150 MW) in September 2016 with plans to retire both in 2020. Finally, the company retired two coal units, the Boswell Units 1 and 2 coal plants, totaling 135 MW in 2018, leaving it with 975 MW of coal generation capacity.

MP's exposure to natural gas fired generation currently only consists of 110 MW of capacity. However, the company recently received regulatory approval for a new jointly owned gas fired power plant for a total capacity of 525-550 MW. MP expects to begin construction on the plant in 2021 and bringing it online by 2025.

Although the fuel mix diversification is a credit positive, the need to maintain access to reliable cost competitive energy to retain its industrial customer base will require some coal generation to continue and will leave the company exposed to potentially costly environmental laws and regulations that will likely require further plant retrofits.

MODERATE CARBON TRANSITION RISK

ALLETE has moderate carbon transition risk amongst its peers in the US regulated utility sector. Although ALLETE's primary utility subsidiary maintains a relatively sizeable coal generation fleet, with its share accounting for 43% of power supplies, its unregulated renewable power business, ALLETE Clean Energy, mitigates some of its carbon transition risk. ALLETE's renewable energy capacity has grown to exceed its coal generation capacity, totaling about 1.1 GW across its regulated utility and ACE business lines.

Moody's framework for assessing carbon transition risk in the utility industry is discussed in "Prudent regulation key to mitigating risk, capturing opportunities of decarbonization" (November 2, 2017).

ALLETE'S RELATIVELY SMALL UNREGULATED BUSINESS ADDS A MODICUM OF RISK

Following the recent sale of US Water Services (US Water, not rated) which we view as credit positive given the inherent volatility of the business and its relatively small size, ALLETE's unregulated business now primarily consists of ACE.

ALLETE has rapidly grown its portfolio of contracted renewable assets over the past four years. ACE has acquired seven wind farms and currently owns 556 MW of wind assets across multiple states. Going forward we expect the pace of growth to subside some. Although these assets are fully contracted with investment grade offtakers, the stability of their cash flow generation is tied to fluctuating wind PPAs. The re-contracting risk the PPAs carry creates uncertainty about the future cash flow generation potential of these assets.

Overall, ALLETE's rating assumes that the company's unregulated segment will remain modest relative to the consolidated group, and its business risk profile will not jeopardize the overall stability and predictability of the company's operating cash flows.

Liquidity analysis

ALLETE's liquidity is adequate. As of 31 December 2018, the company had $69 million in cash on its balance sheet and $382 million available under its $400 million, 5-year revolving bank facility set to expire in January 2024. Borrowings under the bank facility are not subject to a material adverse change clause; however, there is a cross-default clause to other indebtedness (>$35 million). The sole financial covenant in ALLETE's revolving credit facility is a maximum funded debt to total capital covenant of 65%. As of 31 December 2018, ALLETE's debt/cap ratio was approximately 41%.

ALLETE's debt maturity profile is manageable. The company has $75 million of first mortgage bonds due in 2020.

As of 31 December 2018, the company generated $433 million in operating cash flow, invested $312 million in capital investments, and distributed $115 million in dividends to its shareholders, resulting in a positive free cash flow position of $6 million that the company used to pay down debt. Going forward, we expect the company to become free cash flow negative given its lower than anticipated utility rates, an increase in capital expenditures, and the company's stated target dividend payout ratio of 60-65%. We expect the company will fund this cash shortfall through a mix of cash on hand and draws under its revolver.

Rating methodology and scorecard factors

Exhibit 4
Rating Factors
ALLETE, Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current FY 12/31/2018		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Baa	Baa	Baa	Baa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Ba	Ba	B	B
b) Generation and Fuel Diversity	B	B	Ba	Ba
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.1x	Aa	5.7x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	22.3%	A	19% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	16.1%	Baa	12% - 15%	Baa
d) Debt / Capitalization (3 Year Avg)	42.6%	A	40% - 45%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		Baa1
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 12/31/2018
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 5

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18
As Adjusted					
FFO	**340**	**407**	**358**	**393**	**369**
+/- Other	(19)	(3)	18	20	17
CFO Pre-WC	**321**	**404**	**376**	**413**	**387**
+/- ΔWC	(9)	(32)	(6)	25	88
CFO	**313**	**373**	**370**	**438**	**475**
- Div	84	98	103	109	115
- Capex	585	302	280	224	325
FCF	**(357)**	**(27)**	**(13)**	**106**	**35**
(CFO Pre-W/C) / Debt	19.9%	21.7%	20.6%	23.6%	22.7%
(CFO Pre-W/C - Dividends) / Debt	14.7%	16.4%	15.0%	17.4%	16.0%
FFO / Debt	21.0%	21.9%	19.6%	22.5%	21.7%
RCF / Debt	15.8%	16.6%	14.0%	16.2%	14.9%
Revenue	1,137	1,486	1,340	1,419	1,499
Cost of Good Sold	347	321	334	390	402
Interest Expense	58	73	79	76	77
Net Income	128	144	153	168	131
Total Assets	4,431	4,964	4,945	5,150	5,223
Total Liabilities	2,822	3,156	3,063	3,092	3,077
Total Equity	1,609	1,808	1,882	2,058	2,147

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months.

Source: Moody's Financial Metrics

Exhibit 6

Peer Comparison Table [1]

	ALLETE, Inc. Baa1 Stable			Otter Tail Power Company A3 Stable			Northern States Power Company (Minnesota) (P)A2 Stable			Interstate Power and Light Company Baa1 Negative		
(in US millions)	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-16	FYE Dec-17	LTM Mar-18	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-16	FYE Dec-17	FYE Dec-18
Revenue	1,340	1,419	1,499	427	435	439	4,900	5,102	5,122	1,820	1,870	2,042
CFO Pre-W/C	376	413	387	121	137	124	1,369	1,461	1,357	376	418	495
Total Debt	1,823	1,748	1,703	560	603	615	5,410	5,467	5,414	2,459	2,703	3,008
CFO Pre-W/C / Debt	20.6%	23.6%	22.7%	21.5%	22.7%	20.1%	25.3%	26.7%	25.1%	15.3%	15.4%	16.5%
CFO Pre-W/C – Dividends / Debt	15.0%	17.4%	16.0%	14.6%	16.0%	13.5%	18.0%	17.5%	16.6%	9.3%	9.9%	11.0%
Debt / Capitalization	42.8%	43.3%	41.8%	41.9%	48.0%	47.8%	40.3%	44.0%	43.0%	39.1%	43.6%	42.6%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade

Source: Moody's Financial Metrics

Ratings

Exhibit 7

Category	Moody's Rating
ALLETE, INC.	
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
Senior Secured	A2
Bkd LT IRB/PC	A3
SUPERIOR WATER, LIGHT AND POWER COMPANY	
Outlook	Stable
Issuer Rating	A3
Senior Secured	A1

Source: Moody's Investors Service

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S
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FitchRatings

Fitch Downgrades CenterPoint Energy Houston Electric to 'BBB+'; Affirms CNP; Outlooks Negative

Fitch Ratings - New York - 19 February 2020:

Fitch Rating has downgraded CenterPoint Energy Houston Electric's (CEHE) Long-Term Issuer Default Rating (IDR) to 'BBB+' from 'A-'. The Rating Outlook has been revised to Negative from Stable. In addition, Fitch has affirmed CenterPoint Energy Corp.'s (CNP) Long-Term IDR at 'BBB' and has revised the Rating Outlook to Negative from Stable. A full list of rating actions follows at the end of this release.

Today's rating action follows the approval of CEHE's rate case settlement by the Public Utilities Commission of Texas (PUCT) on Feb. 14, 2020. Fitch believes that the unfavorable outcome signals a more challenging regulatory environment in Texas for CEHE. Lower authorized returns and equity capitalization, combined with tax-reform related refund will pressure CEHE's and CNP's credit metrics in the next few years. Further negative rating action is possible if CEHE's and CNP's FFO adjusted leverage sustains above 5x and 5.2x, respectively. Although the proposed sale of the Infrastructure Services business will facilitate debt reduction and improve CNP's operating risk modestly, Fitch estimates that the transaction has minimal impact on the consolidated FFO adjusted leverage ratio.

RATING ACTIONS

ENTITY/DEBT	RATING	PRIOR
CenterPoint Energy, Inc.	LT IDR BBB Affirmed	BBB
	ST IDR F2 Affirmed	F2
senior unsecured	LT BBB Affirmed	BBB
junior subordinated	LT BB+ Affirmed	BB+
senior secured	LT A Downgrade	A+
preferred	LT BB+ Affirmed	BB+
senior unsecured	ST F2 Affirmed	F2
senior unsecured	ULT BBB Affirmed	BBB

senior secured	ULT A Downgrade		A+
CenterPoint Energy Houston Electric, LLC	LT IDR BBB+ Downgrade		A-
	ST IDR F2 Affirmed		F2
senior unsecured	LT A- Downgrade		A
senior secured	LT A Downgrade		A+

Key Rating Drivers

Negative Rate Case: On Feb. 14, 2020, the PUCT approved CEHE's rate case settlement, authorizing a $13 million or 0.52% base rate increase. The increase reflects a 9.4% Return on Equity (ROE) and 42.5% equity capitalization, below the existing 10% authorized ROE and 45% equity ratio, and lower than the industry's average authorized ROE. The ROE is the lowest among all transmission and distribution utilities operating in Texas while the equity capitalization is average. CEHE will refund $105 million federal tax reform-related unprotected excess accumulated deferred federal income tax, or UEDIT, over a three-year period. CEHE also agreed to not file for the Distribution Cost Recovery Factor (DCRF) in 2020. New rates will take effect 45 days after the approval of the order.

Credit Metrics: The rate case has material negative impact on CEHE and CNP's credit metrics. Barring any mitigating actions, Fitch estimates that CEHE's FFO adjusted leverage will range in the high 4x to low 5x in the next three years, and that CNP's FFO adjusted leverage will hover around the 5.3x guideline ratio for a downgrade. The leverage ratio has incorporated the expected sale of the Infrastructure Services business.

Regulatory Ring-fencing Enhances Protection: The rate order will impose a set of regulatory ring-fencing measures but does not include certain dividend restrictions. The ring-fencing provisions will further enhance credit separation among CEHE, CNP and affiliates and are complimentary to the existing corporate governance structure. The existing money pool arrangement will remain.

Asset Sale Modestly Improves Business Risk: The proposed sale of the unregulated Infrastructure Services business will mildly improve CNP's credit profile, increasing its utilities earnings to 80% over the next few years from 75%. However, the transaction has minimal impact on the consolidated FFO adjusted leverage ratio, as the earnings loss will largely offset the debt reduction.

Rating Linkages: Generally, absence of guarantees and cross-defaults, and dividend restrictions among other factors render legal ties weak between CEHE and CNP. While operational and strategic ties are strong between them, a prescribed regulatory capital structure for CEHE lead to weak linkage with CNP. Fitch typically restricts the IDR notching differential to two notches.

Fitch applies a bottom-up approach in rating CEHE and CNP. CEHE's ratings reflect their stand-alone credit profile while CNP's ratings reflect a consolidated credit profile. Fitch considers CEHE stronger than CNP, due to its lower operating risks as a fully regulated transmission and distribution company. Conversely, CNP's investment in Enable and other unregulated businesses carry higher risks than the regulated operations.

Historically, high level of parent only debt (>25%) have also resulted in weaker credit metrics at CNP. Upon the reduction of equity layer at CEHE and debt paydown at CNP as a result of the sale of the Infrastructure Services business, CNP's parent-level debt is expected to decline.

Derivation Summary

CNP carries higher operating risks than the fully regulated NiSource Inc. (NiSource, BBB/Stable), due to its investment in the Enable Midstream Partners (Enable; BBB-/Stable) and other non-utility businesses. Similar to Sempra Energy (BBB+/Stable), approximately 75% of CNP's earnings (including its share of Enable's distribution) is from regulated utilities. Upon the closing of the sale of the Infrastructure Services business, utilities could represent 80% of the total earnings over the next few years. However, Fitch considers Enable's midstream business riskier than Sempra's Cameron liquefied natural gas project, which is fully contracted and has no commodity risks. CNP's utilities are more geographically diversified and more insulated from the aggressive renewable standards and wildfire risks than Sempra's California utilities. CNP and OGE Energy (BBB+/Stable) are both exposed to the commodity sensitive midstream business through Enable. CNP's utility operations are diversified, whereas OGE's only utility is concentrated in Oklahoma. CNP and OGE both experienced negative regulatory treatment. Absent any offsetting measures after the rate case, CNP's FFO-adjusted leverage is estimated to be in the low to mid-5x in the next two years, weaker than Sempra Energy's 5x and OGE Energy's 3.8x. NiSource's credit metrics were affected by the gas explosions in 2018, but expected to return to normal after receiving insurance proceeds and equity issuances.

Prior to the rate case, CEHE benefited from slightly more favorable regulatory treatment than its peers. CEHE's 2010 rate case authorized a 45% equity ratio, higher than Oncor Electric Delivery Company's (BBB+/Stable) 42.5% and AEP Texas Inc.'s (BBB+/Stable) 40%, and the same as Texas-New Mexico Power Company's (TNMP; not rated) equity ratio. CEHE's existing 10% authorized ROE was higher than AEP Texas' 9.98%, Oncor's 9.8% and TNMP's 9.65%. Going forward, CEHE's 9.4% ROE will lag behind its peers while the 42.5% equity ratio is relatively on par. Fitch estimates that CEHE's FFO adjusted leverage could range from high 4x to low 5x in the next two to three years. Oncor and AEP Texas's FFO adjusted leverage are estimated to be in high 4x for the same period.

Key Assumptions

- New rates are implemented in April 2019;

- DCRF resumes in 2021;

- Incorporated the sale of Infrastructure Services business and reduce debt at CNP;

- No mitigating actions are assumed.

RATING SENSITIVITIES

CEHE

Developments That May, Individually or Collectively, Lead to Positive Rating Action

-The Rating Outlook can be revised to Stable if FFO adjusted leverage is below 5x on a sustained basis.

Developments That May, Individually or Collectively, Lead to Negative Rating Action

-FFO-adjusted leverage exceeds 5.0x on a sustained basis;

-Termination of the two trackers TCOS and DCRF;

-Further signs of deterioration of regulatory relationship.

CNP

Developments That May, Individually or Collectively, Lead to Positive Rating Action

-The Rating Outlook can be stabilized if the CNP's FFO adjusted leverage is below 5.3x on a sustained basis;

Developments That May, Individually or Collectively, Lead to Negative Rating Action

-FFO adjusted leverage reaches 5.3x on a sustained basis;

-If CNP and Vectren's utilities' regulatory environment becomes unfavorable to the point that they are unable to receive timely and reasonable recovery in rates;

-Enable requires a meaningful amount of equity support;

-Disproportionate expansion of unregulated businesses resulting in material increase in business risk.

ESG Considerations

Unless otherwise disclosed in this section, the highest level of Environmental, Social and Governance (ESG) credit relevance is a score of '3', which indicates ESG issues are credit neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

Additional information is available on www.fitchratings.com

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Applicable Criteria

Corporate Rating Criteria (pub. 19 Feb 2019)
Short-Term Ratings Criteria (pub. 02 May 2019)
Parent and Subsidiary Rating Linkage (pub. 27 Sep 2019)
Corporates Notching and Recovery Ratings Criteria (pub. 14 Oct 2019)
Corporate Hybrids Treatment and Notching Criteria (pub. 11 Nov 2019)

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RATING ACTION COMMENTARY

Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative

Tue 12 Oct, 2021 - 10:52 AM ET

Fitch Ratings - Chicago - 12 Oct 2021: Fitch Ratings has downgraded the Issuer Default Ratings (IDRs) of both Pinnacle West Capital Corp. (PNW), and its regulated utility subsidiary, Arizona Public Service Co. (APS) to 'BBB+' from 'A-'. The Rating Outlook remains Negative for PNW and APS. Fitch has also downgraded the unsecured ratings of PNW and APS one-notch to 'BBB+' from 'A-' and to 'A-' from 'A', respectively. In addition, Fitch has affirmed the CP and short-term ratings of both PNW and APS at 'F2'.

The one-notch rating downgrade and Negative Outlook for PNW and APS reflect anticipation of an adverse final order in APS's pending general rate case (GRC), resulting pressure on credit metrics and a heightened risk profile. The rating action follows recent amendments to the Administrative Law Judge's (ALJ) recommended order as voted on by the Arizona Corporation Commission (ACC) that, if finalized, would reduce rates at APS more than previously anticipated and lower its authorized ROE to 8.7% from 10%.

Absent future regulatory relief or management action to rebalance its capital structure, Fitch believes FFO leverage could deteriorate to 5.0x or more for PNW and APS in 2023. In that scenario, weaker credit metrics combined with significantly higher regulatory risk would likely result in future adverse credit rating actions.

A final GRC decision expected in late-October or early November along with clarity on management's capital spending plans and funding needs will be key factors in resolving the Negative Outlooks.

KEY RATING DRIVERS

GRC Update: Fitch views ACC amendments to the ALJ's recommended order in APS's pending GRC that would result in a lower revenue requirement and significantly lower authorized ROE as punitive. Based on the ACC amendments, APS's authorized ROE would be reduced to 8.7% from 10% and recovery of investment in selective catalytic reduction (SCR) pollution controls at the Four Corners coal plant would be moved to a separate proceeding further delaying potential cost recovery. APS has been seeking recovery of SCR related costs since 2017.

While the ACC withdrew amendments to eliminate APS's fuel and purchased power adjustment mechanism, Fitch believes roll back of the cost recovery mechanism would significantly heighten business risk, underscoring the regulatory uncertainty facing APS.

Recommended ALJ Order: The ALJ recommendation calls for a revenue increase of $3.6 million based on a 9.16% ROE and an equity layer of 54.7%. APS had previously requested a revised revenue increase of $169 million based on a 10% ROE and an equity layer of 54.7%. Costs associated with the SCR's accounted for nearly half of the requested rate increase. Fitch notes that the recommended ROE of 8.7% is meaningfully below the 2020 national average of 9.4% for electric utilities and materially below APS's current authorized ROE of 10%.

Fitch's rating case reflects recent amendments to the ALJ recommended order as voted on by the ACC. The outcome of the GRC will be a key determinant of credit quality, this being APS's first rate case before the ACC in over three years based on a rate base that is 33% higher than the prior rate case.

Growing Regulatory Headwinds: Recent efforts by regulators to reduce rates, lower authorized returns and promote retail competition highlights the deterioration of the regulatory compact in Arizona. A series of recent decisions by the ACC that has delayed rate recovery and exacerbated regulatory lag have had negative implications for APS's and PNW's credit quality. In Fitch's view, recent amendments to the ALJ's recommended order by the ACC to lower rates and authorized returns, continued delays in approval of the second-step Four Corners rate increase, a recent proposal to remove the fuel and purchased power adjustor among other tracking mechanisms and an investigation into the prudency of the Solana PPA underscores regulatory risk and could result in future adverse credit rating actions.

Weakening Credit Metrics: Assuming APS receives a final order in its GRC consistent with recent ACC amendments, Fitch estimates FFO leverage metrics at both PNW and APS could weaken to 5.8x and 5.3x, respectively, by 2023, supporting the downgrade and Negative Outlook.

Large Utility Capex Program: Fitch expects capex to be elevated throughout the forecast period. Fitch notes that management has lowered the pace of its capital spending program relative to last year as it navigates an increasingly challenging regulatory environment. PNW is targeting average annual utility capex of $1.5 billion in 2021-2023, levels approximately 22% higher than the preceding three-year period but approximately $600 million less than the prior plan.

PNW is focused on achieving a cleaner generation mix while modernizing the electrical grid and spending levels support average rate base growth of 6% through 2023. Capex is earmarked for new generation, distribution and transmission investments including increasing solar generation with battery storage. Generation and distribution investments represent the lion's share of capex, accounting for approximately 75% of total expenditures.

Going forward, PNW plans to align its utility generation mix with Arizona's energy policy goals by divesting its coal fleet by 2031 and investing in new gas-fired generation and solar-battery storage investments. Due to its large capex program, Fitch expects FCF to be moderately negative through 2023, funding the majority of projected capex internally. PNW's external capital needs are expected to be funded by a balanced mix of debt and equity.

Clean Energy Plan: On Jan. 22, 2020, APS announced a self-imposed goal to deliver 100% clean, carbon-free electricity to its customers by 2050. In addition, APS intends to achieve a 2030 resource mix that is 65% clean energy with 45% from renewables while ceasing all coal-fired generation operations by 2031. The company's latest Integrated Resource Plan highlights the need for approximately 2,500MW of renewable energy, demand response, energy efficiency and energy storage resources over the next five years. The clean energy plan is consistent with the ACC proposals for increased renewable standards and should garner support from stakeholders who have been advocating for a cleaner energy future in Arizona.

Strong Economy in Arizona: Economic conditions are strong in Arizona. The utility continues to benefit from strong demographic trends including accelerated customer and retail sales growth. Customer growth approximated 2.3% and retail sales growth of 5.7% during the second quarter.

Parent and Subsidiary Linkage: Operating utility APS accounts for virtually all of parent PNW's consolidated earnings and cash flows. As such, Fitch applies a bottom up, weak parent-strong subsidiary approach in assessing parent-subsidiary rating linkage, reflecting PNW's dependence on APS to meet its obligations. APS's ratings reflect its standalone credit profile, while PNW's ratings reflect a consolidated credit profile.

Strategic and operational ties between PNW and APS are strong and include common call centers and a shared treasury team while legal ties are weak due to regulatory ring- fencing provisions at the utility. Financial ties are moderate as APS has direct access to debt capital markets, but is reliant on equity from its corporate parent. Overall, Fitch assesses parent subsidiary linkage as weak. Consequently, Fitch considers the maximum difference between the IDRs of APS and PNW to be two notches. However, PNW's IDR is the same as APS's, reflecting required support from the utility to meet corporate parent obligations and dependence of APS on equity infusions from PNW and the structural subordination of PNW's debt relative to APS.

ESG RELEVANCE FACTOR THAT IS A KEY RATING DRIVER

ESG Factors: Fitch has revised the ESG relevance score to '5' for '4' for both Social - Human Rights, Community Relations, Access & Affordability and Social - Customer Welfare-Fair Messaging, Privacy & Data Security factors for both PNW and APS to reflect recent deterioration in the regulatory environment in Arizona and expectations for a challenging decision in APS's pending GRC. Regulatory risk has increased following a recent decision by the ACC to reduce customer rates and authorized returns. This has a negative impact on the credit profile and is relevant to the ratings in conjunction with other factors.

DERIVATION SUMMARY

Pinnacle West Capital Corp.:

Pinnacle West Capital Corp.'s credit profile is in line with lower rated peer utility parent holding companies DTE Energy Co. (BBB/Stable) and CMS Energy Corp. (BBB/Stable). A weakening financial profile resulting from regulatory lag due to a deteriorating regulatory environment has pressured credit metrics, which are in line with 'BBB' peers. While the regulatory environment in Michigan remains supportive, the regulatory environment in

Arizona has become challenging as evidenced by the punitive recommended order in APS's pending GRC and recent amendments voted out by the commission. For 2020, FFO adjusted leverage at PNW was 5.6x, worse than DTE at 4.7x but better than CMS at 6.3x.

PNW's business risk profile reflects ownership of sole subsidiary APS Co. and is comparable to peers with predominantly electric operations in single state jurisdictions. PNW's regulated utility operations comprise 100% of EBITDA and its business risk is similar to CMS -- which derives approximately 95% of EBITDA from its regulated utility and DTE -- which derives more than 90% of EBITDA from regulated utility businesses. In terms of scale, PNW's utility operations are the largest in Arizona with total assets of $21 billion as of 2020 but are smaller in size relative to CMS and DTE. DTE and CMS are the largest utility providers in Michigan with total assets of $50 billion and $30 billion as of 2020, respectively.

Arizona Public Service Company:

The credit profile of APS is weaker than utility peers DTE Electric Co. (A-/Stable) and Florida Power and Light Co. (A/Stable). APS's credit profile is comparable with peers that have sizable electric utility operations in single-state jurisdictions with historically constructive regulatory environments. The regulatory environment in Arizona has deteriorated meaningfully becoming significantly more challenging from a credit perspective compared to Michigan or Florida. The ACC appears to be focused on potential overearnings and reducing customer rates. This is most evident in the ALJ's unfavorable recommended order in APS's latest GRC and recent amendments by the ACC to the ALJ's recommended order.

Credit metrics for APS are weaker than peers due to regulatory lag resulting from a protracted GRC proceeding during a period of heavy capex. For 2020, FFO adjusted leverage at APS was 5.2x, worse than DTE Electric at 3.9x and Florida Power and Light Co. at 2.9x. In terms of scale, APS's utility operations are the largest in Arizona but smaller relative to DTE Electric and Florida Power and Light

KEY ASSUMPTIONS

--Assumes a rate reduction based on 8.7% ROE;

--Continued customer growth averaging 2% per annum;

--Capex averaging $1.5 billion per annum through 2023.

RATING SENSITIVITIES

PNW:

Factors that could, individually or collectively, lead to positive rating action/upgrade;

--A positive rating action is unlikely at this time given the Negative Outlook;

--However, improvement in the regulatory compact in Arizona could stabilize the Negative Rating Outlook;

--Sustained FFO leverage of better than 4.0x along with an improving regulatory compact could lead to a favorable rating action.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Continued deterioration in the regulatory compact in Arizona.

--A material increase in parent-level debt;

--A downgrade at APS;

--Sustained FFO leverage greater than 5.0x.

APS:

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--A positive rating action is unlikely at this time given the Negative Outlook;

--However, improvement in the regulatory compact in Arizona could stabilize the Negative Outlook;

--Sustained FFO leverage of better than 4.0x along with an improving regulatory compact could lead to a favorable rating action.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Continued deterioration in the regulatory compact in Arizona;

--Sustained FFO leverage greater than 5.0x.

BEST/WORST CASE RATING SCENARIO

International scale credit ratings of Non-Financial Corporate issuers have a best-case rating upgrade scenario (defined as the 99th percentile of rating transitions, measured in a positive direction) of three notches over a three-year rating horizon; and a worst-case rating downgrade scenario (defined as the 99th percentile of rating transitions, measured in a negative direction) of four notches over three years. The complete span of best- and worst-case scenario credit ratings for all rating categories ranges from 'AAA' to 'D'. Best- and worst-case scenario credit ratings are based on historical performance. For more information about the methodology used to determine sector-specific best- and worst-case scenario credit ratings, visit https://www.fitchratings.com/site/re/10111579.

LIQUIDITY AND DEBT STRUCTURE

Sufficient Liquidity: Fitch considers liquidity for PNW to be adequate with $709 million of available liquidity under its consolidated credit facilities as of June 30, 2021, including $14 million of unrestricted cash and cash equivalents. PNW's liquidity is provided by a $200 million unsecured credit facility that matures in May 2026 and a $150 million term loan that matures in June 2022. APS's liquidity is provided by two $500 million unsecured credit facilities that mature in May 2026. These facilities support its $750 million CP program. PNW and APS can upsize their $200 million and $500 million credit facilities to $300 million and $700 million, respectively, with lender consent.

The credit facilities are subject to a maximum debt/capitalization covenant of 65% and as of June 30, 2021, PNW and APS complied with debt/capitalization ratios of 55% and 50% as defined under the agreement. APS requires modest cash on hand and, being a summer peaking utility, capital needs are typically highest during the second and third quarters. PNW's long-term debt maturities are minimal over the next five years and includes $250 million in 2024 and $300 million in 2025 at APS.

ISSUER PROFILE

PNW is a parent holding company which derives virtually all of its revenue from its wholly owned sole operating subsidiary, APS. APS is a regulated vertically integrated electric utility, serving 1.3 million customers in a 34,646-square-mile service territory. APS is the largest electric utility in Arizona and serves most of the Phoenix metropolitan area.

REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

ESG CONSIDERATIONS

ESG Factors: We have revised the ESG relevance score to '5' for '4' for both Social - Human Rights, Community Relations, Access & Affordability and Social - Customer Welfare-Fair Messaging, Privacy & Data Security factors for both PNW and APS to reflect recent deterioration in the regulatory environment in Arizona and expectations for a challenging decision in APS's pending GRC. Regulatory risk has increased following a recent decision by the ACC to reduce customer rates and authorized returns. This has a negative impact on the credit profile and is relevant to the ratings in conjunction with other factors.

In 2019, both PNW and APS were assigned an ESG relevance score of '4' for Social issues following complaints of excessive bills by customers following the implementation of time-of-use rates. Regulators have found that customer education and outreach efforts were insufficient, which has led to increased regulatory scrutiny and the absence of rate recovery.

Unless otherwise disclosed in this section, the highest level of ESG credit relevance is a score of '3'. This means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

RATING ACTIONS

ENTITY/DEBT	RATING			PRIOR
Arizona Public Service Company	LT IDR	BBB+ Rating Outlook Negative	Downgrade	A- Rating Outlook Negative
	ST IDR	F2	Affirmed	F2
• senior unsecured	LT	A-	Downgrade	A

ENTITY/DEBT	RATING			PRIOR
• senior unsecured	LT	A-	Downgrade	A

VIEW ADDITIONAL RATING DETAILS

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APPLICABLE CRITERIA

Parent and Subsidiary Linkage Rating Criteria (pub. 26 Aug 2020)

Corporate Rating Criteria -- Effective from 21 December 2020 to 15 October 2021 (pub. 21 Dec 2020) (including rating assumption sensitivity)

Corporates Recovery Ratings and Instrument Ratings Criteria (pub. 09 Apr 2021) (including rating assumption sensitivity)

Sector Navigators - Addendum to the Corporate Rating Criteria - Effective from 30 April 2021 to 15 October 2021 (pub. 30 Apr 2021)

APPLICABLE MODELS

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

Corporate Monitoring & Forecasting Model (COMFORT Model), v7.9.0 (1)

ADDITIONAL DISCLOSURES

Dodd-Frank Rating Information Disclosure Form

Solicitation Status

Endorsement Policy

ENDORSEMENT STATUS

Arizona Public Service Company	EU Endorsed, UK Endorsed
Pinnacle West Capital Corporation	EU Endorsed, UK Endorsed

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Energy and Natural Resources Corporate Finance Utilities and Power North America

United States

7 Oct, 2021

Pinnacle West shares tumble after regulators slash returns in rate case

Author **Allison Good**

Theme **Energy**

Pinnacle West Capital Corp. shares tumbled more than 6% in midday trading Oct. 7 after state regulators voted to slash subsidiary Arizona Public Service Co.'s return on equity to 8.7% from 10.0%, a reduction described by some analysts as "draconian."

By the end of the trading day, Pinnacle West stock dropped more than 8%, closing at $68.19 on nearly five times average volume.

Arizona Public Service sought a 10% return on equity that would translate to a $40.2 million base rate increase. In August, an administrative law judge recommended a 9.16% ROE that would have required the utility to implement a $111.4 million rate reduction. The 4-1 vote by the Arizona Corporation Commission on Oct. 6 after three days of hearings reduced the ROE further. (Docket No. E-01345A-19-0236)

Explaining the decision, Commissioner Justin Olson cited "poor customer education, implementation, the challenges with the rate design tool, and the calculation of recommended rate and so on and so forth," according to a report by Phoenix news station ABC15. A similar amendment that would have cut the return for Arizona Public Service even further reportedly failed by a vote of 4-1.

Ahead of the vote, Pinnacle West Chairman, President and CEO Jeffrey Guldner reportedly told commissioners any ROE reduction below 9.1% would impair the utility's ability to make investments to accommodate the population and economic growth of its service territory.

Sector analysts at Guggenheim Securities LLC and Wells Fargo Securities LLC said the commission's decision jeopardizes ratepayers' interests.

"The Commission has voted to adopt amendments which would cause an already overly punitive [recommended opinion and order] to become draconian," Guggenheim analysts wrote in an Oct. 7 report.

"Arizona Corporation Commission is now confirmed to be the single most value destructive regulatory environment in the country as far as investor-owned utilities are concerned," Guggenheim's analysts continued. "Rather than positioning itself as a steward of good public policy and a guardian of ratepayers' interests, as is often the case in other states, the [Arizona Corporation Commission] does not appear to take a cooperative approach to the companies it regulates, and worse, seems to misconstrue the fundamentals of utility ratemaking."

In a separate vote, the commission also delayed a decision on whether Arizona Public Service can recover the costs of installing selective catalytic reduction equipment at the 1,540-MW Four Corners coal-fired plant, which Wells Fargo analysts noted as "another sign of continued deterioration in the Arizona regulatory environment."

"While in our view the circumstances were somewhat unique (customer service issues, last major coal investment, pandemic backdrop), we think the sum of the [Arizona Corporation Commission's] decisions push the bounds of onerous rate case outcomes," they wrote in an Oct. 6 note.

Guldner said during the company's Aug. 5 second-quarter earnings call that disallowing the deferral and investment, which the administrative law judge recommended, would compromise reliability.

"If we didn't have the capacity out of Four Corners, there's nothing else in the West," Guldner said. "There's nothing else that we could go get. There's no other resource that we could use to keep the lights on. ... That's why I'm struggling in particular with this recommendation. It has been clearly demonstrated over the last two summers as not just used and useful but necessary from a capacity basis in the face of a bunch of challenges around capacity."

RRA REGULATORY FOCUS

Commission accords Arizona Public Service Company a well below average ROE

Friday, October 8, 2021 8:30 AM ET

By Jim Davis
Market Intelligence

The Arizona Corporation Commission, or ACC, recently voted at an open meeting to authorize Arizona Public Service Co., or APS, a return on equity of 8.7% in the context of the utility's pending base rate case (Docket No. E-01345A-19-0236). The ACC voted to adopt a proposal by Republican Commissioner Justin Olson that specifies an authorized capital structure containing a 54.67% common equity component and overall returns of 6.62% and 4.73% on unspecified original-cost and fair-value rate bases, respectively. APS is a subsidiary of Pinnacle West Capital Corp.

The commission's deliberations regarding the other aspects of the rate case are ongoing, and it is unclear when a final decision and a final written order will be forthcoming from the commission.

While the ACC has not yet rendered a final decision in the proceeding, the adopted ROE is below both the 9.4% equity return recommended by the ACC staff and the 9.16% ROE recommended by the administrative law judge assigned to the case. Equity return recommendations by intervenors in the case ranged from 8.7% to 10%, and the adopted 8.7% ROE is equivalent to that recommended by the residential utility consumers office, or RUCO. Notably, RUCO's ROE recommendation incorporated a downward adjustment of 20 basis points to penalize APS for "demonstrated poor customer service." As asserted by RUCO and adopted by the ACC, this primarily pertains to the company's customer education/outreach programs associated with numerous rate design changes adopted in APS' prior rate case. The adjustment also involves a decline in the utility's ranking in a customer satisfaction index relative to other western U.S. utilities.

The authorized 8.7% ROE is well below the 9.43% and 9.44% average of returns accorded to electric utilities in all cases decided in first-half 2021 and full-year 2020, respectively, according to Regulatory Research Associates, a group within S&P Global Market Intelligence. For vertically integrated utilities such as APS, the average equity return through the first six months of 2021 and the full year 2020 was 9.46% and 9.55%, respectively. This authorized equity return is among the lowest ROEs RRA has encountered in its coverage of vertically integrated electric utilities in the past 30 years. For further information regarding trends in ROE authorizations, refer to RRA's Major Rate Case Decisions Quarterly Updates.

As calculated by RRA, incorporating the ACC's authorized ROE into the rate change proposal supported by APS would reduce the utility's requested rate change from a $40.2 million rate hike to a $45.3 million rate reduction. Notably, this calculation does not account for changes to the company's requested level of return premium associated with fair-value rate base.

Case history

This case began Oct. 1, 2019, when APS filed a notice of intent to initiate a rate case. On Oct. 31, 2019, APS submitted its formal filing with the ACC for a $68.6 million rate increase premised upon a 10.15% return on equity (54.67% of capital) and a 7.41% return on a year-end $8.873 billion original cost rate base for a test year ended June 30, 2019.

The APS filing also specified a 5.62% return on a $12.31 billion fair value rate base. It appears that the company request reflected a $45.6 million premium associated with fair-value rate base. RRA calculates that this is roughly equivalent to a 10.86% ROE and a 7.79% overall return on an original-cost rate base.

The initial company filing reflected the transfer to base rates of amounts from certain adjustment clauses. This included a $119.3 million credit from APS' tax expense adjustor mechanism, or TEAM, rider. Partially offsetting the TEAM credit was the transfer to base rates of $3.9 million from the environmental surcharge, or EIS, rider and $0.3 million from the renewable energy adjustment charge, or REAC. Excluding these items, the proposed rate hike would have amounted to $183.6 million.

APS was required to file this rate case pursuant to a 2019 ACC order that was issued in the context of an investigation regarding the utility's earnings.

In rebuttal testimony filed Nov. 6, 2020, APS supported a $40.5 million rate increase. The increase was premised upon a 10% return on equity (54.67% of capital) and a 7.33% return on an original cost rate base valued at $8.896 billion.

The company's rebuttal filing also specified a 5.51% return on a $12.315 billion fair value rate base. This included a $36 million premium associated with fair-value rate base. RRA calculates that this equates approximately to a 10.56% ROE and a 7.63% return on original-cost rate base.

Excluding the transfer to base rates of amounts being recovered from certain riders, including the roughly $119 million credit from the TEAM rider and about $4 million total from the EIS rider and the REAC, the supported rate increase would have been equivalent to approximately $156 million.

APS subsequently filed post-hearing testimony supporting a revised $40.2 million rate increase premised upon a 10% return on equity (54.67% of capital) and a 7.33% return on an original-cost rate base valued at $8.896 billion.

The post-hearing testimony also specified a 5.51% return on a $12.315 billion fair-value rate base. The revised position appears to reflect a $36 million premium associated with a return on fair-value rate base. RRA calculates that this premium equates to a 10.56% ROE and a 7.63% overall return on an original-cost basis.

APS' revised position did not include updated information regarding the impact of the various riders that had been presented earlier in the proceeding.

The ACC staff filed testimony Oct. 2, 2020, recommending that the company be required to reduce rates by $25.3 million. The rate reduction was premised upon a 9.4% return on equity (54.67% of capital) and a 7% return on an original-cost rate base valued at $8.788 billion.

The staff's filing also specified a 5.11% return on a $12.225 billion fair-value rate base. It appears that the staff recommendation reflected a $13.5 million premium associated with a return on fair-value rate base. RRA calculated that this was equivalent to a 10.4% ROE and a 7.54% return on original-cost rate base.

The staff filing reflected the transfer to base rates of amounts from certain adjustment clauses, as was proposed by APS in its initial filing. This included a $119.3 million credit from the TEAM rider. Partially offsetting the TEAM credit was the transfer to base rates of $3.9 million from the EIS rider and $0.3 million from the REAC. Excluding these items, the staff recommendation would have amounted to a rate increase of roughly $89.7 million.

On Aug. 2, 2021, the administrative law judge issued a recommended decision calling for APS to implement a rate reduction of $111.4 million premised upon a 9.16% return on equity (54.67% of capital) and a 6.87% return on a year-end original-cost rate base valued at $8.325 billion for a test year ended June 30, 2019.

The judge also recommended a 4.95% return on an $11.744 billion fair-value rate base, with a premium of $12.5 million associated with a return on fair-value rate base. RRA calculates that the premium equated to a 9.37% ROE and a 6.98% return on original-cost rate base.

Among other recommendations, the judge proposed to exclude from rate base APS' investment in selective catalytic reduction, or SCR, equipment at the Four Corners facility. The SCR equipment was installed on units 5 and 4 in late 2017 and spring 2018, respectively. APS was supposed to implement a step increase related to the SCR equipment as part of its previous rate case, pursuant to a settlement. A Nov. 27, 2018, recommendation issued by an administrative law judge had called for APS to implement a $58.5 million incremental rate increase pertaining to the SCRs in January 2019. However, the ACC never acted on that recommendation and the SCR investments were subsequently incorporated into the company's filing in the instant rate case.

Prior case

Prior to the instant decision, APS was authorized a 10% ROE as established in a 2017 ACC rate decision that followed a settlement (in Docket No. E-01345A-16-0036). As mentioned above in this article, a proposed step increase that was specified in the adopted settlement in that docket and was supposed to be implemented by APS in January 2019 was never approved by the commission.

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In Texas, calls to boost U.S. oil production after Russian invasion run into hard realities

Labor shortages, supply chain issues, hesitant financial backers and a frosty relationship with the Biden administration have limited how much Texas oil and gas companies are ramping up production.

BY **MITCHELL FERMAN** MARCH 25, 2022 5 AM CENTRAL

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A pumpjack outside of Midland. Eli Hartman for The Texas Tribune

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MIDLAND — After Russia invaded Ukraine last month and the U.S. and major energy companies boycotted Russian oil and gas, some politicians quickly called for cranking up American energy production to fill the void.

A Republican member of Congress attended President Joe Biden's State of the Union address earlier this month wearing a shirt emblazoned with "Drill baby drill." U.S. Rep. Filemon Vela, a Democrat from Brownsville, tweeted, "Save Ukraine! Unleash American Oil and Gas!"

And U.S. Rep. August Pfluger, R-San Angelo, who represents the heart of Texas' oil patch, has printed red, white and blue baseball caps with an oil pump jack next to the words "Midland over Moscow."

"The energy producers of [West Texas] and America are READY to produce the energy our nation and allies need!" Pfluger wrote on Twitter.

U.S. Rep. Lauren Boebert, R-Colo., wears a shawl with "Drill Baby Drill" printed on it before President Joe Biden's State of the Union address on March 1, 2022. Win McNamee/Pool

But in Texas' Permian Basin — the nation's most productive oil region and the place that would have to lead any jump in U.S. production — people in the industry, energy analysts and local leaders say there's no quick or easy way to make that happen.

Cranking up production requires more workers, materials and money, and people in the industry say they're facing the same labor shortages and supply chain issues that have plagued countless businesses throughout the COVID-19 pandemic. On top of that, they say Wall Street investors have become more hesitant about pouring money into fossil fuels, and the Biden administration's policies are hampering the oil and gas industry.

"It's hard to get pipe, sand, crews for drilling rigs, truck drivers," said Mike Oestmann, CEO of Tall City Exploration, a company that drills oil wells in West Texas and has two active rigs that drill 32 wells per year combined. He said the scarcity of supplies, equipment and people "is unlike anything I've ever seen."

He said frac sand — a key ingredient in the hydraulic fracturing process — has been particularly hard to find due in part to labor shortages, even though much of the supply comes from Texas. The price of steel has increased so much that supply shortages make it hard to get pipe for drilling wells, he added. Oestmann said his company has no plans to add more drilling rigs, but even if it did, he said it probably wouldn't be able to find the supplies to do so.

"And I talked to a guy yesterday — a bigger company than us — trying to ramp up his operation to six rigs, and he goes, 'I don't know if I can get all the things I need to do that,'" Oestmann said.

John Volke, CEO of Crew Support Services — a company that houses oil field workers in temporary quarters known as "man camps" — says his company has filled every one of its 1,500 beds in the Permian.

"Every one of our clients are trying to hire 20 to 40 people — field hands, labor for rigging pipe," Volke said. "I don't know where these people went to work, Amazon?"

First: A roofing crew begins to shingle a home under construction in a new Midland housing development as a pumpjack operates nearby. Last: Motorists drive past a sign hiring workers in Midland. Eli Hartman for The Texas Tribune

Oestmann said when the demand for oil and gas plummeted at the start of the pandemic, many oil field workers got out of the industry for good.

“We quit drilling for a year, a lot of people slowed down,” Oestmann said. “All those people that were working in the field, a lot of them just said, enough’s enough. I’m out.”

Juan Cano left the industry in 2019 and isn’t returning.

The 57-year-old has worked many jobs over the years — driving trucks, laying asphalt and now fixing vehicles at a Midland auto shop. Like many people living in the Permian Basin, he’s been lured into oil field jobs during previous booms. But even with oil-related businesses desperate for workers and the price of oil topping $100 a barrel following Russia’s invasion of Ukraine, Cano said the appeal of more money isn’t strong enough this time.

“I don’t want to go back into that up and down swing,” Cano said last week outside the auto shop. “It’s not stable, especially now with everything going on in the world.”

Motorists drive along Interstate 20 past a gas station in Odessa. 📷 Eli Hartman for The Texas Tribune

Replacing Russian oil?

The Biden administration announced a U.S. boycott of Russian oil on March 8, but only about 7% of U.S. oil imports come from Russia. A handful of other countries like Britain and Canada, plus some major energy companies like ExxonMobil and Shell, have also stopped buying Russian oil. The International Energy Agency estimates that by April, 3 million barrels per day of Russian oil production could be off the global market "as sanctions take hold and buyers shun exports."

But nearly all European countries that rely heavily on Russian oil haven't followed the U.S. lead, and Biden hasn't pushed other countries much on the issue for fear that such a boycott could hurt the world economy more than it hurts Russia.

The world consumes around 100 million barrels of oil per day, and Russia produces about 11.2 million barrels per day, making it the third-largest producer behind the U.S. and Saudi Arabia. The IEA, which was formed after the 1973 oil crisis to ensure a steady worldwide energy market, said the repercussions of Russia's invasion are likely to grow over the next several months as summer driving season begins.

Former Midland Mayor Bobby Burns, now president of the Midland Chamber of Commerce, speaks during a lecture titled "Midland Fuels America" on March 15 at the Permian Basin Petroleum Museum in Midland. Eli Hartman for The Texas Tribune

"The world may well be facing its biggest oil supply shock in decades, with huge implications for our economies and societies," said IEA Executive Director Fatih Birol, citing the uncertain future of Russian supplies on the global market as the war continues and sanctions against the nation mount.

In the U.S., no place drills for oil as much as the Permian Basin. As of March 11, the region had 316 oil rigs in the ground — the number continually flashes on a large screen in downtown Midland along with the current temperature. The rest of the U.S. had 212 rigs, according to the Federal Reserve Bank of Dallas. (Each rig can have dozens of individual wells.) The Permian produces more than 5 million of the nation's daily output of 11.6 million barrels of oil per day.

Local officials say the war in Ukraine, which has pushed the price of oil up 58% from the start of the year, will boost profits for the oil and gas already being produced in the Permian Basin.

"When the world's supply is interrupted, which it is, it just makes our product that much more important," Bobby Burns, president of the Midland Chamber of Commerce and the city's former mayor, said last week at the Permian Basin Petroleum Museum.

"We're of mixed minds" about the Russia-Ukraine conflict, Burns added. "We know it's strengthening our bottom line, but it's bad for the world."

Before Russia invaded Ukraine, the Permian Basin's oil production had finally surpassed pre-pandemic levels as the global economy recovered. The U.S. Energy Information Administration forecasts that production in the Permian region will average 5.3 million barrels per day in 2022 and will reach 5.7 million barrels per day in 2023, which would be a record high.

The Odessa Spire is lit in the colors of the Ukrainian flag in support of Odessa's sister city in Ukraine after Russia's invasion of that country. Eli Hartman for The Texas Tribune

Some investors are less bullish on oil investments

To significantly boost production in the Permian, companies have to secure major financial backing.

Historically, that backing has come from Wall Street, which "has dictated tremendously what goes on in the industry out here," said Stephen Robertson, executive vice president of the Permian Basin Petroleum Association, adding that drillers decide how much oil to produce "one way or another based on signals [they] are getting from Wall Street."

Prior to the pandemic, Wall Street was already starting to see oil and gas as a riskier investment because of environmental concerns, said Steven Beach, dean of the business school at the University of Texas Permian Basin.

For example, the Rockefeller family — which became wealthy and famous in the late 1800s from founding the Standard Oil empire, whose successors include Chevron and ExxonMobil — sold off all its fossil fuel investments in 2015 because of concerns about climate change.

Other investors have cooled on the energy sector for purely bottom-line reasons. More than half of 132 oil and gas executives surveyed by the Dallas Fed said this week that pressure by investors to provide a better return on investments is the main reason energy companies are "restraining growth despite high oil prices."

Beach said energy company shareholders "were wondering why their companies produced so much oil and gas from 2017-19 and it was so dirt cheap, and at the end of the day, they didn't really make much money out of it."

Matt Coday, president and founder of the Oil & Gas Workers Association based in Odessa, blamed the Biden administration's decisions on energy policy for some of investors' hesitancy to put money into the industry. He said Biden signaled to the industry on his first day in office that he does not support oil and gas by suspending the Keystone XL pipeline.

Coday said the administration's decision to halt new oil leases on federal land also created a chilling effect within the industry.

"We've got [U.S. Treasury Secretary] Janet Yellen asking banks to defund fossil fuel projects," Coday said, referring to Yellen's push for banks to align their portfolios with the world's climate goals, which includes cutting investments in oil and gas.

Still, the world relies heavily on oil and gas, and Beach said the ongoing labor shortages, supply chain problems, and financial and political uncertainty are creating major headwinds for energy companies trying to meet the demand.

"The confluence of these issues are making it more challenging for companies to decide whether they're going to start ramping up production again," Beach said.

Disclosure: The University of Texas Permian Basin, Exxon Mobil Corporation and the Permian Basin Petroleum Association have been financial supporters of The Texas Tribune, a nonprofit, nonpartisan news organization that is funded in part by donations from members, foundations and corporate sponsors. Financial supporters play no role in the Tribune's journalism. Find a complete list of them here.

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SOURCE: https://www.bls.gov/cpi/data.htm
STEPS: Use "All Urban Consumers (Current Series) and "One Screen"; then use "U.S. City Average" and "All Items" and "Seasonally Adjusted", hit "Add to Selection" and then hit "Get Data".
**** ONLY PASTE SPECIAL VALUES INTO MATRIX BELOW (NEED TO MAINTAIN NUMBER HEADERS) ****

CPI for All Urban Consumers (CPI-U)
Original Data Value

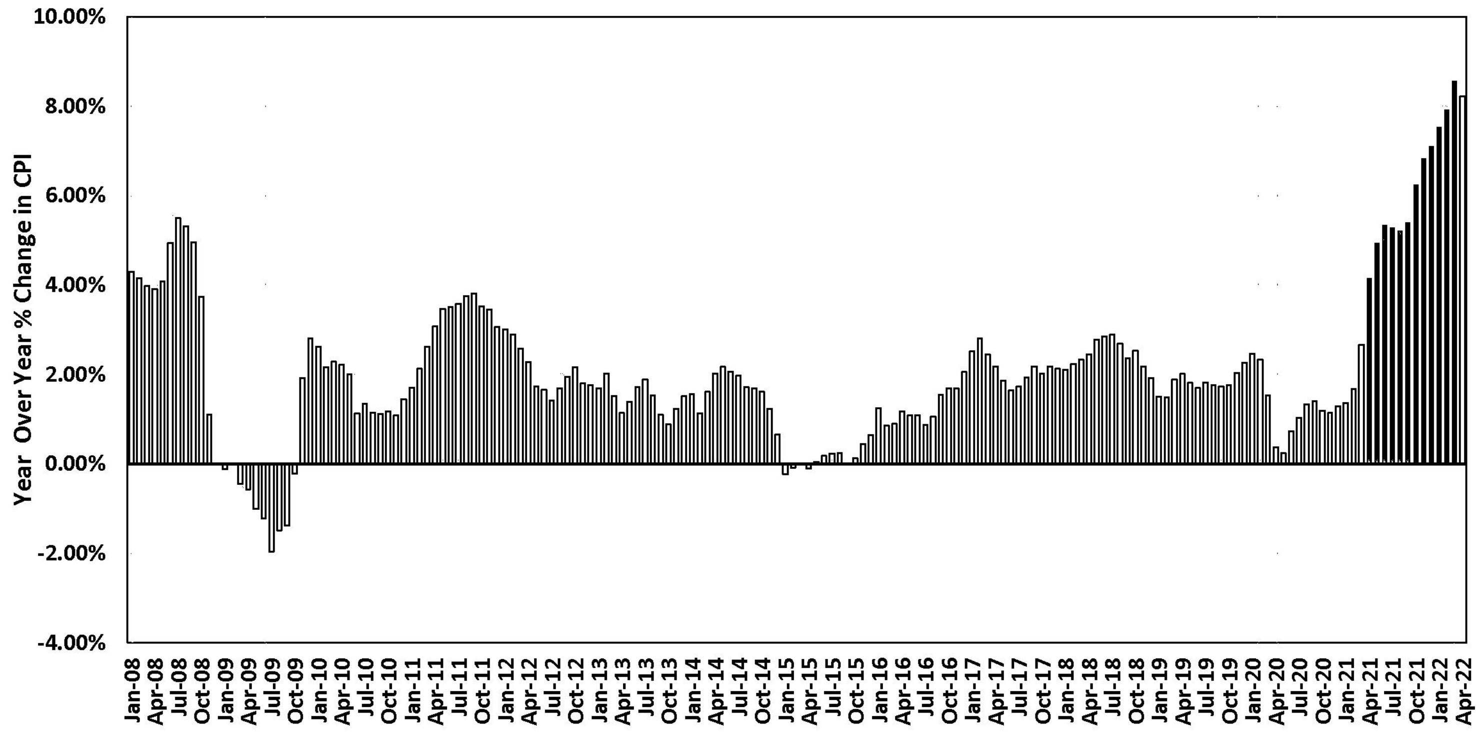
Series Id:	CUSR0000SA0
Seasonally Adjusted	
Series Title:	All items in U.S. city average, all urban consumers,
Area:	U.S. city average
Item:	All items
Base Period:	1982-84=100
Years:	2006 to 2022

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**HALF1**	**HALF2**
2006	199.3	199.4	199.7	200.7	201.3	201.8	202.9	203.8	202.8	201.9	202.0	203.1		
2007	203.437	204.226	205.288	205.904	206.755	207.234	207.603	207.667	208.547	209.190	210.834	211.445		
2008	212.174	212.687	213.448	213.942	215.208	217.463	219.016	218.690	218.877	216.995	213.153	211.398		
2009	211.933	212.705	212.495	212.709	213.022	214.790	214.726	215.445	215.861	216.509	217.234	217.347		
2010	217.488	217.281	217.353	217.403	217.290	217.199	217.605	217.923	218.275	219.035	219.590	220.472		
2011	221.187	221.898	223.046	224.093	224.806	224.806	225.395	226.106	226.597	226.750	227.169	227.223		
2012	227.842	228.329	228.807	229.187	228.713	228.524	228.590	229.918	231.015	231.638	231.249	231.221		
2013	231.679	232.937	232.282	231.797	231.893	232.445	232.900	233.456	233.544	233.669	234.100	234.719		
2014	235.288	235.547	236.028	236.468	236.918	237.231	237.498	237.460	237.477	237.430	236.983	236.252		
2015	234.747	235.342	235.976	236.222	237.001	237.657	238.034	238.033	237.498	237.733	238.017	237.761		
2016	237.652	237.336	238.080	238.992	239.557	240.222	240.101	240.545	241.176	241.741	242.026	242.637		
2017	243.618	244.006	243.892	244.193	244.004	244.163	244.243	245.183	246.435	246.626	247.284	247.805		
2018	248.743	249.439	249.581	250.146	250.779	251.118	251.323	251.749	252.239	252.862	252.657	252.551		
2019	252.470	253.135	254.273	255.163	255.325	255.361	255.900	256.179	256.596	257.305	257.788	258.263		
2020	258.682	259.007	258.165	256.094	255.944	257.217	258.543	259.580	260.190	260.352	260.721	261.564		
2021	262.200	263.346	265.028	266.727	268.599	270.955	272.184	273.092	274.214	276.590	278.524	280.126		
2022	281.933	284.182	287.708	288.663										

Date	Month	Year	CPI	YOY % Change	Recession
Jan-06	1	2006	199.3		
Feb-06	2	2006	199.4		
Mar-06	3	2006	199.7		
Apr-06	4	2006	200.7		
May-06	5	2006	201.3		
Jun-06	6	2006	201.8		
Jul-06	7	2006	202.9		
Aug-06	8	2006	203.8		
Sep-06	9	2006	202.8		
Oct-06	10	2006	201.9		
Nov-06	11	2006	202		
Dec-06	12	2006	203.1		
Jan-07	1	2007	203.437	2.08%	-1
Feb-07	2	2007	204.226	2.42%	-1
Mar-07	3	2007	205.288	2.80%	-1
Apr-07	4	2007	205.904	2.59%	-1
May-07	5	2007	206.755	2.71%	-1
Jun-07	6	2007	207.234	2.69%	-1
Jul-07	7	2007	207.603	2.32%	-1
Aug-07	8	2007	207.667	1.90%	-1
Sep-07	9	2007	208.547	2.83%	-1
Oct-07	10	2007	209.19	3.61%	-1
Nov-07	11	2007	210.834	4.37%	-1
Dec-07	12	2007	211.445	4.11%	1
Jan-08	1	2008	212.174	4.29%	1
Feb-08	2	2008	212.687	4.14%	1
Mar-08	3	2008	213.448	3.97%	1
Apr-08	4	2008	213.942	3.90%	1
May-08	5	2008	215.208	4.09%	1
Jun-08	6	2008	217.463	4.94%	1
Jul-08	7	2008	219.016	5.50%	1
Aug-08	8	2008	218.69	5.31%	1
Sep-08	9	2008	218.877	4.95%	1
Oct-08	10	2008	216.995	3.73%	1
Nov-08	11	2008	213.153	1.10%	1
Dec-08	12	2008	211.398	-0.02%	1
Jan-09	1	2009	211.933	-0.11%	1
Feb-09	2	2009	212.705	0.01%	1
Mar-09	3	2009	212.495	-0.45%	1
Apr-09	4	2009	212.709	-0.58%	1
May-09	5	2009	213.022	-1.02%	1
Jun-09	6	2009	214.79	-1.23%	1
Jul-09	7	2009	214.726	-1.96%	-1
Aug-09	8	2009	215.445	-1.48%	-1
Sep-09	9	2009	215.861	-1.38%	-1
Oct-09	10	2009	216.509	-0.22%	-1
Nov-09	11	2009	217.234	1.91%	-1
Dec-09	12	2009	217.347	2.81%	-1
Jan-10	1	2010	217.488	2.62%	-1
Feb-10	2	2010	217.281	2.15%	-1
Mar-10	3	2010	217.353	2.29%	-1
Apr-10	4	2010	217.403	2.21%	-1
May-10	5	2010	217.29	2.00%	-1
Jun-10	6	2010	217.199	1.12%	-1
Jul-10	7	2010	217.605	1.34%	-1
Aug-10	8	2010	217.923	1.15%	-1
Sep-10	9	2010	218.275	1.12%	-1
Oct-10	10	2010	219.035	1.17%	-1
Nov-10	11	2010	219.59	1.08%	-1
Dec-10	12	2010	220.472	1.44%	-1
Jan-11	1	2011	221.187	1.70%	-1
Feb-11	2	2011	221.898	2.12%	-1
Mar-11	3	2011	223.046	2.62%	-1
Apr-11	4	2011	224.093	3.08%	-1
May-11	5	2011	224.806	3.46%	-1
Jun-11	6	2011	224.806	3.50%	-1
Jul-11	7	2011	225.395	3.58%	-1
Aug-11	8	2011	226.106	3.75%	-1
Sep-11	9	2011	226.597	3.81%	-1

Date	Month	Year	CPI	YOY % Change	Recession
Oct-11	10	2011	226.75	3.52%	-1
Nov-11	11	2011	227.169	3.45%	-1
Dec-11	12	2011	227.223	3.06%	-1
Jan-12	1	2012	227.842	3.01%	-1
Feb-12	2	2012	228.329	2.90%	-1
Mar-12	3	2012	228.807	2.58%	-1
Apr-12	4	2012	229.187	2.27%	-1
May-12	5	2012	228.713	1.74%	-1
Jun-12	6	2012	228.524	1.65%	-1
Jul-12	7	2012	228.59	1.42%	-1
Aug-12	8	2012	229.918	1.69%	-1
Sep-12	9	2012	231.015	1.95%	-1
Oct-12	10	2012	231.638	2.16%	-1
Nov-12	11	2012	231.249	1.80%	-1
Dec-12	12	2012	231.221	1.76%	-1
Jan-13	1	2013	231.679	1.68%	-1
Feb-13	2	2013	232.937	2.02%	-1
Mar-13	3	2013	232.282	1.52%	-1
Apr-13	4	2013	231.797	1.14%	-1
May-13	5	2013	231.893	1.39%	-1
Jun-13	6	2013	232.445	1.72%	-1
Jul-13	7	2013	232.9	1.89%	-1
Aug-13	8	2013	233.456	1.54%	-1
Sep-13	9	2013	233.544	1.09%	-1
Oct-13	10	2013	233.669	0.88%	-1
Nov-13	11	2013	234.1	1.23%	-1
Dec-13	12	2013	234.719	1.51%	-1
Jan-14	1	2014	235.288	1.56%	-1
Feb-14	2	2014	235.547	1.12%	-1
Mar-14	3	2014	236.028	1.61%	-1
Apr-14	4	2014	236.468	2.02%	-1
May-14	5	2014	236.918	2.17%	-1
Jun-14	6	2014	237.231	2.06%	-1
Jul-14	7	2014	237.498	1.97%	-1
Aug-14	8	2014	237.46	1.72%	-1
Sep-14	9	2014	237.477	1.68%	-1
Oct-14	10	2014	237.43	1.61%	-1
Nov-14	11	2014	236.983	1.23%	-1
Dec-14	12	2014	236.252	0.65%	-1
Jan-15	1	2015	234.747	-0.23%	-1
Feb-15	2	2015	235.342	-0.09%	-1
Mar-15	3	2015	235.976	-0.02%	-1
Apr-15	4	2015	236.222	-0.10%	-1
May-15	5	2015	237.001	0.04%	-1
Jun-15	6	2015	237.657	0.18%	-1
Jul-15	7	2015	238.034	0.23%	-1
Aug-15	8	2015	238.033	0.24%	-1
Sep-15	9	2015	237.498	0.01%	-1
Oct-15	10	2015	237.733	0.13%	-1
Nov-15	11	2015	238.017	0.44%	-1
Dec-15	12	2015	237.761	0.64%	-1
Jan-16	1	2016	237.652	1.24%	-1
Feb-16	2	2016	237.336	0.85%	-1
Mar-16	3	2016	238.08	0.89%	-1
Apr-16	4	2016	238.992	1.17%	-1
May-16	5	2016	239.557	1.08%	-1
Jun-16	6	2016	240.222	1.08%	-1
Jul-16	7	2016	240.101	0.87%	-1
Aug-16	8	2016	240.545	1.06%	-1
Sep-16	9	2016	241.176	1.55%	-1
Oct-16	10	2016	241.741	1.69%	-1
Nov-16	11	2016	242.026	1.68%	-1
Dec-16	12	2016	242.637	2.05%	-1
Jan-17	1	2017	243.618	2.51%	-1
Feb-17	2	2017	244.006	2.81%	-1
Mar-17	3	2017	243.892	2.44%	-1
Apr-17	4	2017	244.193	2.18%	-1
May-17	5	2017	244.004	1.86%	-1
Jun-17	6	2017	244.163	1.64%	-1

Date	Month	Year	CPI	YOY % Change	Recession
Jul-17	7	2017	244.243	1.73%	-1
Aug-17	8	2017	245.183	1.93%	-1
Sep-17	9	2017	246.435	2.18%	-1
Oct-17	10	2017	246.626	2.02%	-1
Nov-17	11	2017	247.284	2.17%	-1
Dec-17	12	2017	247.805	2.13%	-1
Jan-18	1	2018	248.743	2.10%	-1
Feb-18	2	2018	249.439	2.23%	-1
Mar-18	3	2018	249.581	2.33%	-1
Apr-18	4	2018	250.146	2.44%	-1
May-18	5	2018	250.779	2.78%	-1
Jun-18	6	2018	251.118	2.85%	-1
Jul-18	7	2018	251.323	2.90%	-1
Aug-18	8	2018	251.749	2.68%	-1
Sep-18	9	2018	252.239	2.36%	-1
Oct-18	10	2018	252.862	2.53%	-1
Nov-18	11	2018	252.657	2.17%	-1
Dec-18	12	2018	252.551	1.92%	-1
Jan-19	1	2019	252.47	1.50%	-1
Feb-19	2	2019	253.135	1.48%	-1
Mar-19	3	2019	254.273	1.88%	-1
Apr-19	4	2019	255.163	2.01%	-1
May-19	5	2019	255.325	1.81%	-1
Jun-19	6	2019	255.361	1.69%	-1
Jul-19	7	2019	255.9	1.82%	-1
Aug-19	8	2019	256.179	1.76%	-1
Sep-19	9	2019	256.596	1.73%	-1
Oct-19	10	2019	257.305	1.76%	-1
Nov-19	11	2019	257.788	2.03%	-1
Dec-19	12	2019	258.263	2.26%	-1
Jan-20	1	2020	258.682	2.46%	-1
Feb-20	2	2020	259.007	2.32%	1
Mar-20	3	2020	258.165	1.53%	1
Apr-20	4	2020	256.094	0.36%	1
May-20	5	2020	255.944	0.24%	-1
Jun-20	6	2020	257.217	0.73%	-1
Jul-20	7	2020	258.543	1.03%	-1
Aug-20	8	2020	259.58	1.33%	-1
Sep-20	9	2020	260.19	1.40%	-1
Oct-20	10	2020	260.352	1.18%	-1
Nov-20	11	2020	260.721	1.14%	-1
Dec-20	12	2020	261.564	1.28%	-1
Jan-21	1	2021	262.2	1.36%	-1
Feb-21	2	2021	263.346	1.68%	-1
Mar-21	3	2021	265.028	2.66%	-1
Apr-21	4	2021	266.727	4.15%	-1
May-21	5	2021	268.599	4.94%	-1
Jun-21	6	2021	270.955	5.34%	-1
Jul-21	7	2021	272.184	5.28%	-1
Aug-21	8	2021	273.092	5.21%	-1
Sep-21	9	2021	274.214	5.39%	-1
Oct-21	10	2021	276.59	6.24%	-1
Nov-21	11	2021	278.524	6.83%	-1
Dec-21	12	2021	280.126	7.10%	-1



Putting in -1 in column F for all months, then no shading; change to 1 in months want shading

Customer Concentration Risk and the Cost of Equity Capital*

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ABSTRACT

This study investigates the relation between customer concentration and a supplier's cost of equity capital. We hypothesize that a more concentrated customer base increases a supplier's risk, which results in a higher cost of equity. Our results show a positive association between customer concentration and a supplier's cost of equity, and this relation is more pronounced for suppliers that are more likely to lose major customers or that are more prone to larger losses if they lose such customers. Further, results from a propensity score matched sample analysis and instrumental variables regressions imply that our findings are robust to accounting for endogeneity. We also provide evidence that a supplier with a concentrated base of safer government customers has a lower cost of equity. Finally, we document a positive relation between corporate customer concentration and a supplier's cost of debt. Overall, our findings suggest that the composition and concentration of a supplier's customer base significantly impact its financing costs.

Keywords: Cost of equity, Customer concentration, Business risk, Cost of debt

JEL Classifications: G12; M41

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1. Introduction

Business risks stemming from a firm's business model and operating environment are important determinants of its cost of equity capital (Modigliani and Miller, 1958). One characteristic that regulators, researchers, and practitioners view as important in assessing the risks inherent in a firm's current and future cash flows is the concentration of the firm's customer base. For instance, Statement of Financial Accounting Standards (SFAS) No. 131 (previously SFAS No. 14) requires firms disclose information about major customers because these customers represent "a significant concentration of risk." The SEC under Regulation S-K Item 101 also has similar disclosure requirements. Further, anecdotal evidence suggests that firms explicitly recognize this risk.[1] While approximately 45% of public firms report relying on at least one customer for a sizeable portion of revenues (Ellis et al., 2012), there is surprisingly little empirical evidence on whether customer concentration risk affects firms' financing costs. In this study, we aim to fill this gap by investigating the relation between the concentration of a supplier's customer base and its cost of equity.

Depending on a major customer for a large portion of sales can be risky for a supplier for two primary reasons.[2] First, a supplier faces the risk of losing substantial future sales if a major customer becomes financially distressed or declares bankruptcy, switches to a different supplier, or decides to develop products internally. Consistent with this notion, Hertzel et al. (2008) and Kolay et al. (2015) document negative supplier abnormal stock returns to the announcement that a major customer declares bankruptcy.[3,4]

[1] For example, Tenneco Inc. in its 2011 annual report states that "the loss of all or a substantial portion of our sales to any of our large-volume customers could have a material adverse effect on our financial condition and results of operations by reducing cash flows and our ability to spread costs over a larger revenue base."

[2] Dhaliwal et al. (2014) similarly outline the sources of risks associated with a concentrated customer base.

[3] Anecdotal evidence also supports this notion. For example, Lovable Garments, a large producer of women's lingerie in the 1990s, lost Wal-Mart as a major customer when Wal-Mart switched to various suppliers outside the U.S. This loss caused a significant reduction in annual income for Lovable Garments and led to the company filing for Chapter 11 bankruptcy.

[4] To an extent, a supplier can reduce the risk that a major customer will switch to a different supplier or develop products internally by writing explicit sales contracts that lock in sales to the customer. However, studies have found that few firms have supply contracts (Costello, 2013), which is consistent with the conventional view that implicit contracts typically govern customer-supplier relationships because it is very costly to write explicit contracts covering all possible contingencies (Bowen et al., 1995; Shleifer and Summers, 1988).

Further, a customer's weak financial condition or actions could signal inherent problems about the supplier's viability to its remaining customers and lead to compounding losses in sales. Second, a supplier faces the risk of losing anticipated cash flows from being unable to collect outstanding receivables if the customer goes bankrupt.[5] This assertion is consistent with the finding that suppliers offering customers more trade credit experience larger negative abnormal stock returns around the announcement of a customer filing for Chapter 11 bankruptcy (Jorion and Zhang, 2009; Kolay et al., 2015).

While the above evidence suggests that a concentrated customer base can increase a supplier's risk, whether this risk is priced into a supplier's cost of equity is unclear and thus an empirical question. To test the relation between customer concentration and a supplier's cost of equity, we first create three measures that capture various dimensions of customer concentration over the years 1981 to 2011. Next, we follow prior research and measure a supplier's cost of equity as the average of several implied cost of equity estimates derived from analysts' earnings forecasts (e.g., Hail and Leuz, 2006; Li, 2010). In our empirical tests, we control for omitted variables that can affect all suppliers in the same industry during any given year and several characteristics known to impact a supplier's cost of equity.

Across all three measures of customer concentration, we find evidence that greater risk associated with a concentrated customer base results in a higher cost of equity. Our findings suggest that a supplier that depends on one or more major customers for at least 10% of its annual revenues has a cost of equity that is 21.2 basis points higher, which represents an additional annual cost of $7.99 million for the average supplier to finance with equity. This effect is economically significant relative to our other control variables, such as measures of information asymmetry. For instance, the effect of depending on sales

[5] For example, 68% of auto industry supplier executives reported that their companies would have to downsize if General Motors declared bankruptcy and 12% said their businesses would likely or definitely close. In light of this risk and after more than 40 auto-part suppliers filed for Chapter 11 bankruptcy, the U.S. Treasury Department allocated $5 billion in Troubled Asset Relief Program (TARP) funds to compensate suppliers for unpaid merchandise and help them avoid financial collapse. See Steven Gray, "The Ripple Effect of a Potential GM Bankruptcy," *TIME Magazine,* November 28, 2008 and Carl Gutierrez, "Auto Parts Supplier Tap TARP," *Forbes,* March 19, 2009.

from a major customer on a supplier's cost of equity is equivalent to the effect of a 1.5 standard deviation increase in analyst forecast dispersion.

We also document a positive relation between customer concentration and a supplier's systematic risk, as measured by the supplier's equity beta. This finding is consistent with traditional asset pricing theories that suggest that customer concentration risk would have to be related to systematic risk in order to be non-diversifiable and therefore priced into a supplier's cost of equity (e.g., Lambert et al., 2007; Lintner, 1965; Sharpe, 1964). Further, this result supports the conclusion that the risk associated with having a concentrated customer base is in part non-diversifiable.[6]

We also conduct several cross-sectional tests that exploit settings where the risk associated with having a concentrated customer base is predictably larger. If greater customer concentration increases a supplier's risk, then the positive relation between customer concentration and a supplier's cost of equity should be especially strong when these relationships are predictably riskier. Specifically, this relation should be stronger when a supplier has a major customer that is more likely to default or declare bankruptcy or a major customer that has fewer barriers to switching to a different supplier. This relation should also be more pronounced for a supplier that is more likely to have unpaid invoices if a major customer defaults and for a supplier that lacks a diverse stream of revenues that can coinsure against the loss of a major customer. We use several measures to proxy for these situations and find evidence that is consistent with all four predictions.

Our estimates of the effect of customer concentration on a supplier's cost of equity could suffer from an omitted variable bias. In particular, our control variables may

[6] Recent work suggests that a possible alternative reason for why customer concentration risk is priced into a supplier's cost of equity could be due to a relation between customer concentration and firm-specific risk. For example, if there are greater market frictions or local investor biases associated with the stocks of suppliers that depend on at least one major customer for a large portion of revenues, this risk may be priced because investors are unable to fully diversify their portfolios (e.g., Fu, 2009; Malkiel and Xu, 2004; Spiegel and Wang, 2005). In Section 3.2, we document that customer concentration is not only positively related to systematic risk but also positively related to idiosyncratic risk, which is consistent with Albuquerque et al. (2014). Because customer concentration increases both types of risk, we are unable to conclude whether the positive relation between customer concentration and a supplier's cost of equity is driven by systematic risk or idiosyncratic risk. Although we are unable to determine exactly why customer concentration risk is non-diversifiable, this does not affect our main conclusion that a supplier with a more concentrated customer base has a higher cost of equity.

insufficiently account for differences between suppliers that do and do not have concentrated customer bases. Thus, the estimated effect of customer concentration on a supplier's cost of equity could be picking up nonlinear effects of our control variables. We are also unable to observe the extent to which different customer-supplier relationships are governed by implicit versus explicit contracts as well as the extent to which managerial-specific relationships between customers and suppliers affect the risk of losing a major customer. To help alleviate these endogeneity concerns, we perform a propensity score matched sample analysis and implement an instrumental variables approach. The results from both analyses continue to show that a supplier with a more concentrated customer base has a higher cost of equity, suggesting a causal link from customer concentration to a supplier's cost of equity.

The focus of our paper is on the relation between a concentrated base of corporate customers and a supplier's cost of equity. Yet, a supplier can also be highly dependent on revenues from the U.S. federal government. Unlike corporate customers, however, federal government customers are much less likely to default or declare bankruptcy, and government purchases are typically regulated by longer-term procurement contracts (Goldman et al., 2013), which reduce the risk that government customers will switch suppliers. As such, a supplier that depends on the federal government for a large portion of revenues gains operational efficiencies from selling to a major customer but does not bear many of the risks associated with relying on a major corporate customer. Consequently, we expect a negative relation between federal government customer concentration and a supplier's cost of equity. We find that the cost of equity is 19.1 basis points lower for a supplier that depends on the federal government for at least 10% of its annual revenues.

In our last set of analyses, we examine the relation between customer concentration and a supplier's cost of debt. If a supplier with a concentrated base of corporate customers loses a major customer, the financial losses the supplier incurs could limit its ability to service debt payments. As such, we expect that creditors demand a higher rate of return on loans made to a supplier with a more concentrated customer base. We measure a supplier's cost of debt using loan spreads on new issues of both bank loans and public bonds. Our results show that a supplier that depends on at least one major corporate customer has 5.0%-6.0% higher borrowing costs on bank debt and 7.0%-9.9% higher borrowing costs on public bonds. Thus, a concentrated customer base increases a supplier's cost of accessing not only external equity but also debt capital.

We provide new empirical evidence that the concentration of a supplier's customer base impacts its cost of equity. Broadly, this finding contributes to the literature investigating the determinants of a firm's cost of equity. Prior work predominantly focuses on how various forms of information risk affect firms' cost of equity, including voluntary financial and nonfinancial disclosure (Botosan, 1997; Dhaliwal et al., 2011; Francis et al., 2008), earnings transparency (Barth et al., 2013), and internal control quality (Ashbaugh-Skaife et al., 2009). While studies find that business risks stemming from a firm's operating environment and business model tend to have a larger impact than managerial discretion on a firm's cost of equity (Bhattacharya et al., 2012; Francis et al., 2005), they do not identify the sources of such business risks. Our work extends this literature by documenting how a prevalent source of business risk—a concentrated customer base—impacts a firm's financing costs. Our findings also validate the inclusion of a "customer concentration risk premium" as an input in practitioner models of a firm's cost of equity (e.g., Duff & Phelps).[7,8]

Our findings also extend the literature that examines how the concentration of a supplier's customer base affects its characteristics and financial policies. While prior work shows that suppliers with a concentrated base of customers tend to be more profitable because they realize operational efficiencies (Cen et al., 2013; Kalwani and Narayandas, 1995; Patatoukas, 2012), our findings imply that a concentrated customer base raises suppliers' risk and financing costs. Thus, our paper relates to work documenting that a

[7] For example, Metropolitan Health Networks in its 8-K filing provided information about its merger with Continucare Corporation in 2011. This disclosure included a weighted average cost of capital calculation obtained from Continucare Corporation's financial advisor, Barrington Research Associates, Inc., that included a 2% customer concentration risk premium.
[8] See "Risk Premium Report 2013," *Duff & Phelps, LLC.*, 2013.

concentrated customer base is associated with higher idiosyncratic risk and a greater likelihood of receiving a going-concern opinion (Albuquerque et al., 2014; Dhaliwal et al., 2014). Last, several other studies find that suppliers with greater customer concentration tend to maintain lower financial leverage ratios (Banerjee et al., 2008; Kale and Shahrur, 2007), recognize bad news sooner (Hui et al., 2012), have more discretionary accruals (Raman and Shahrur, 2008), hold more cash (Itzkowitz, 2013), and pay fewer dividends (Wang, 2012).

Finally, our study contributes to literature showing that nonfinancial stakeholders have a significant impact on a firm's financing costs. For instance, Chen, Kacperczyk, and Ortiz-Molina (2011) show that labor unions increase labor adjustment costs and make wages stickier, resulting in higher operating leverage and a higher cost of equity. Yet, Chen et al. (2012) find that unionization lowers a firm's cost of debt. In addition to showing that major customers impact a firm's financing costs, we show that the type of customer exposes suppliers to differential business risks. Specifically, we show that a supplier with a major corporate customer has a higher cost of equity and debt, while a supplier with a major federal government customer has a lower cost of equity but not a lower cost of debt.

The remainder of this paper is organized as follows. Section 2 describes our data and empirical methodology. Section 3 reports our empirical findings. Section 4 documents the results of additional robustness tests. Section 5 concludes.

2. Data and Empirical Methodology

2.1. Sample Selection

We obtain data to estimate the implied cost of equity capital from the Institutional Brokers' Estimate System (IBES), customer-supplier data from Compustat's segment customer files, financial statement data from Compustat, and stock return data from the Center for Research in Security Prices (CRSP) files. The intersection of these databases creates our main sample that consists of 44,218 supplier-year observations. This sample includes industrial firms that have publicly-traded stock over the 1981 to 2011 period, are incorporated in the U.S., and have non-missing data for the main variables of interest. We exclude utilities (SIC 4900-4999) and financial firms (SIC 6000-6999). We winsorize continuous variables at their 1st and 99th percentiles to reduce the influence of outliers and express all dollar values in 2009 dollars.

2.2. Implied Cost of Equity Capital Estimates

We empirically estimate the cost of equity that is implied in current stock prices and analysts' earnings forecasts using IBES data as of June in the following year and four cost of equity models introduced by Claus and Thomas (2001), Gebhardt et al. (2001), Easton (2004), and Ohlson and Juettner-Nauroth (2005). The first two models are based on Ohlson's (1995) residual income valuation model, and the latter two models are based on Ohlson and Juettner-Nauroth's abnormal earnings growth valuation model. Appendix A provides a detailed description of the cost of equity estimates. There is little consensus in the literature on which models perform best or how the models should be evaluated (Botosan and Plumlee, 2005; Gode and Mohanram, 2003; Guay et al., 2011). Therefore, we follow prior literature and use the mean of the estimates from the four models as our measure of the cost of equity to mitigate the effect of measurement errors associated with one particular model (Hail and Leuz, 2006; Li, 2010).

Table 1 presents the descriptive statistics and the correlation matrix for the cost of equity estimates. As seen in Panel A, the Ohlson and Juettner-Nauroth (OJN) method generates the highest average estimated cost of equity with a mean of 12.94% and a median of 12.12%. The Gebhardt et al. (GLS) method produces the lowest average estimated cost of equity with a mean of 7.33% and a median of 7.05%. Panel B of Table 1 presents the pairwise Pearson (below the diagonal) and the Spearman (above the diagonal) correlations between the four estimates, which are all positive. The lowest observed Pearson (Spearman) correlation is between the GLS method and the Easton (MPEG) method with a value of 0.473 (0.459). The highest observed Pearson (Spearman) correlation is between the OJN method and the MPEG method with a value of 0.885 (0.863). Overall, our ex ante cost of equity estimates are comparable to those in prior studies (Botosan and Plumlee, 2005; Chen, Chen, and Wei, 2011).

2.3. Measures of Customer Concentration

We use Compustat's segment customer files to identify suppliers that disclose sales to major corporate customers. Since 1976, the Statement of Financial Accounting Standards No. 14 (SFAS 14) of the Financial Accounting Standard Board (FASB) has required a supplier to disclose external customers that individually account for 10% or more of its revenues. FAS 131 superseded SFAS 14 in 1997, but the requirement to report such customers remains intact for public companies under SEC Regulation S-K Item 101. Although regulations require suppliers to identify customers accounting for at least 10% of revenues, suppliers often voluntarily report customers that account for less than 10% of sales. Because these disclosures are voluntary, we do not include these customers in our concentration calculations to reduce concerns of a potential selection bias.[9]

We create three measures to capture the extent to which a supplier's customer base is concentrated. Panel C of Table 1 presents summary statistics for these three concentration measures. For our first measure of customer concentration, we create an indicator variable that is set to one if a supplier discloses at least one corporate customer that accounts for 10% or more of its annual revenues and zero otherwise *(Major Customer)*. In 26% of our observations, a supplier reports that at least one major customer accounts for 10% or more of revenues.

For our second measure, we follow Patatoukas (2012) and use an application of the Herfindahl-Hirschman Index to capture customer concentration *(Customer HHI)*. This measure accounts for both the number of major customers identified by the supplier and the importance of those major customers to the supplier's annual revenues. Thus, we measure supplier i's customer concentration in year t across the supplier's J major customers as:

[9] In robustness tests, we also include customers accounting for less than 10% of a supplier's sales in all of our customer concentration measures. Our results are robust to using these alternative definitions.

$$Customer\ HHI_{it} = \sum_{j=1}^{J} \left(\frac{Sales_{ijt}}{Sales_{it}} \right)^2, \qquad (1)$$

where $Sales_{ijt}$ represents supplier *i*'s sales to major customer *j* in year *t,* and $Sales_{it}$ represents supplier *i*'s total sales in year *t*. This variable ranges between zero and one, with higher values corresponding to a more concentrated customer base. In particular, this measure takes a value of zero for a supplier that does not disclose sales to any major customers and takes a value of one for a supplier that depends on a single major customer for all annual revenues.

Our last measure follows Banerjee et al. (2008) and Dhaliwal et al. (2014) who define *Total Major Customer Sales* as the fraction of a supplier's annual total sales captured by all customers that account for at least 10% of the supplier's annual revenues. For the subset of suppliers that disclose at least one major customer, mean sales to all major customers account for 31% of these suppliers' total revenues.[10]

2.4. General Empirical Methodology

To examine the relation between customer concentration and the implied cost of equity at the supplier-year level, we estimate the following panel regression model:

$$CostofEquity_{it} = a_1(Customer\ Concentration)_{it} + X_{it}\beta + \beta_r \times \beta_t + \varepsilon_{it}, \qquad (2)$$

where $CostofEquity_{it}$ is our measure of the estimated implied cost of equity in excess of the risk-free rate, as measured by the yield on 10-year Treasury bonds, for supplier *i* in year *t*. *Customer Concentration* is one of our three measures of customer concentration. X_{it} is a set of control variables, and $\beta_r \times \beta_t$ are interactions of industry and year fixed effects.[11] Our controls include financial variables commonly found in implied cost of equity regressions

[10] All three of our customer concentration measures are positively correlated. The highest observed Pearson correlation is between *Customer HHI* and *Total Major Customer Sales* with a value of 0.84. The lowest correlation is between *Major Customer* and *Customer HHI* with a value of 0.51. The correlation between *Major Customer* and *Total Major Customer Sales* is 0.77.

[11] We use the equity-risk premium as our dependent variable to be consistent with the estimation of the implied cost of equity in Claus and Thomas (2001), Gebhardt et al. (2001), and Gode and Mohanram (2003). Because we include industry × year fixed effects in our models, subtracting the risk-free rate from each firm's cost of equity is redundant, as the risk-free rate is a yearly constant. We have rerun all of our tests using the cost of equity not in excess of the risk-free rate, and all of the results are robust.

(Campbell et al., 2012; Chen, Chen, and Wei, 2011). These variables include stock return beta and idiosyncratic risk, log market value of equity, the book-to-market ratio, book leverage, return momentum, log analyst forecast dispersion, the forecasted long-term growth rate, and return on assets. Panel C of Table 1 presents summary statistics and detailed definitions for these variables. To ease the interpretation and comparability of coefficient estimates across variables, we standardize all independent variables (except customer concentration measures) to have a mean of zero and a standard deviation of one in multivariate regressions.

We define industries at the 2-digit SIC level. The interaction of industry and year fixed effects (industry × year fixed effects) controls for omitted industry characteristics within a 2-digit SIC industry in a given year. Thus, these fixed effects account for transitory industry-wide factors, such as industry demand shocks, which could affect a supplier's cost of equity and customer concentration risk in any particular year.[12] The estimated standard errors in all regressions are corrected for heteroskedasticity and are clustered at the supplier level to correct for serial correlation within supplier groupings.

3. Empirical Results

3.1. Customer Concentration and the Cost of Equity Capital

We begin our analysis by examining whether a concentrated customer base impacts a supplier's cost of equity. Table 2 presents the results of this analysis. The dependent variable in columns 1-6 is the average implied cost of equity in excess of the risk-free rate (in the remainder of the paper, all models use the implied cost of equity in excess of the risk-free rate, and we refer to it as simply the implied cost of equity).

Columns 1-3 report the results from regression models that include all control

[12] For a full discussion of how fixed effects can remove an omitted variable bias, see Gormley and Matsa (2014). The inclusion of industry × year fixed effects in our regression models is equivalent to demeaning cost of equity estimates, customer concentration measures, and all the other independent variables with respect to their averages by industry each year. Therefore, this step removes all heterogeneity within industries each year and is more general than including industry and year fixed effects separately. Given that our sample is over a 31 year window from 1981 to 2011, it is likely that omitted industry effects will vary over this long time horizon (e.g., industry-level regulatory changes or technological breakthroughs). Thus, it is important to control for industry effects that vary over time.

variables, except equity beta and idiosyncratic risk. The results show a positive and statistically significant relation between a concentrated customer base and a supplier's cost of equity across all three measures of customer concentration. In terms of economic significance, the coefficient estimate on *Major Customer* in column 1 implies that a supplier with at least one major customer has a cost of equity that is 21.2 basis points higher. Given that the sample mean of the implied cost of equity in excess of the risk-free rate is 4.44%, this 21.2 basis point increase translates into a 4.8% (=0.212/4.44) rise in a supplier's cost of equity relative to the sample mean. In addition, the mean (median) supplier has outstanding equity of $3,771 ($779.6) million. Thus, a 21.2 basis point increase in a supplier's cost of equity implies an additional annual cost of $7.99 ($1.65) million for the mean (median) supplier to finance with equity.

To compute the economic significance of having a concentrated customer base using the other two measures of customer concentration in columns 2 and 3, we compare the difference in concentration for suppliers that do not depend on any major customers to the average supplier that depends on at least one major customer. The average supplier with at least one major customer has a customer concentration HHI of 0.09 and a total percentage of sales to all major customers of 31%. Since both measures take the value of zero for suppliers that do not depend on any major customers, the coefficient estimates in columns 2 and 3 imply that the difference in cost of equity between these two types of suppliers is 8.4 (=.932*0.09) basis points and 16.9 (=0.546*0.31) basis points, respectively. For the remainder of the paper, we only calculate the economic significance for the variable identifying whether a supplier has at least one major customer.

Columns 4-6 present the results from the same regression models as those in columns 1-3, but we follow prior literature and include equity beta and idiosyncratic risk as control variables (e.g., Ashbaugh-Skaife et al., 2009; Chen, Chen, and Wei, 2011). We use this model specification throughout the rest of our paper. We estimate *Beta Value-Weighted* by regressing daily individual stock returns over the fiscal year on the contemporaneous CRSP value-weighted market returns and correct the measure for nonsynchronous trading following Scholes and Williams (1977). Similarly, we define idiosyncratic risk as the annualized standard deviation of the residuals from the aforementioned regression that is corrected for nonsynchronous trading following Scholes and Williams (1977).[13]

As expected, the results in columns 4-6 show that the inclusion of equity beta and idiosyncratic risk significantly attenuates the positive relation between customer concentration and a supplier's cost of equity. Specifically, the coefficient estimate in column 4 on the indicator variable for whether a supplier has at least one major customer declines from 0.212 to 0.121. In comparison to the coefficient estimates on the control variables in column 4, we note that this 12.1 basis point increase in the cost of equity for suppliers with at least one major customer remains economically significant. For example, because we standardize all other independent variables to have a mean of zero and a standard deviation of one, a one standard deviation increase in equity beta and analyst forecast dispersion are associated with a 10.3 and 9.1 basis point higher cost of equity, respectively. Moreover, the economic effect of customer concentration on a supplier's cost of equity is about a quarter of the effects of a one standard deviation change in size, the book-to-market ratio, and book leverage.

Table 2 also shows that the signs on the estimated coefficients on the control variables are consistent with previous findings in the literature. The implied cost of equity is positively related to equity beta, idiosyncratic risk, the book-to-market ratio, financial leverage, and analyst forecast dispersion. Similar to Dhaliwal et al. (2006), we also find that the cost of equity is positively related to analysts' forecasted long-term growth rate. Further, the cost of equity is negatively correlated with firm size, price momentum, and profitability. It is worth noting that the economic effects of customer concentration in Table 2 are likely understated, as these results capture the average effect across all suppliers. In Section 3.3, we find that the economic effect of customer concentration is larger for sub-samples of suppliers with a riskier concentrated customer base. Overall, the results in

[13] As a robustness test, we rerun our tests and correct equity beta and idiosyncratic risk for nonsynchronous trading following Dimson (1979), using contemporaneous market returns as well as five leads and lags. We find very similar results.