COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
LOUISVILLE GAS AND ELECTRIC	**)**	
COMPANY AND KENTUCKY UTILITIES	**)**	
COMPANY FOR APPROVAL OF A SOLAR	**)**	
POWER CONTRACT AND TWO	**)**	**CASE NO. 2020-00016**
RENEWABLE POWER AGREEMENTS TO	**)**	
SATISFY CUSTOMER REQUESTSS FOR A	**)**	
RENEWABLE ENERGY SOURCE UNDER	**)**	
GREEN TARIFF OPTION #3	**)**	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY
TO ATTORNEY GENERAL'S THIRD DATA REQUESTS
DATED MARCH 17, 2020

FILED: MARCH 23, 2020

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of March 2020.

Judy Schooler (SEAL)

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of March 2020.

Judy Schooler

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of March 2020.

(SEAL)
Notary Public

Notary Public, ID No. 603967

My Commission Expires:

7/11/2022

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to Attorney General's Third Data Requests
Dated March 17, 2020

Case No. 2020-00016

Question No. 1

Witness: David S. Sinclair

Q-1. Reference the responses to AG DR 2-17 and PSC 2-1. Confirm the following:

a. The Companies are currently meeting the energy needs of all customers, including the two industrial customers at issue, and will continue to be able to do so even if the Commission does not approve the instant application.

b. The Companies' obligation to procure energy at the lowest reasonable costs does not require that the Companies retire or mothball existing generation resources.

c. Even if the Companies retire or mothball one or more generating units in order to procure power under the proposed PPA, customers would continue to pay the undepreciated costs (stranded costs) attendant to the to-be retired or mothballed units.

d. In the event the Commission approves the proposed PPA, to the extent the Companies have to back off of existing generation, customers will be paying not only for the power produced under the PPA, but also all costs associated with the continued operation of the existing generation units, including but not limited to O&M and depreciation.

e. If the Companies have to back off of existing generation for native load, the excess power from the existing generating units should be available for dispatch in off-system sales, to the extent such sales are possible.

f. None of the Companies' existing generating assets have been fuly depreciated.

g. All of the Companies' existing generating units are used and useful.

A-1.

a. The premise to the request for confirmation is unreasonable. As the Companies state in their application, the energy and associated renewable energy credit ("REC") sales from the Solar Power Contract will be used to reduce customers' future energy costs and are not being procured for reliability purposes.

The Companies presently have two industrial customers that have requested pursuant Green Tariff Option 3 a 75 MW of energy from renewable resources to meet new demand. Under Green Tariff Option #3, the requests of these two industrial customers for energy from renewable resources must be generated from a renewable resource developed on or after the Kentucky Public Service Commission has approved a special contract between each customer and the Companies. Therefore, the Companies are unable to meet these industrial customers new demand without approval of the purchased power agreement with Rhudes Creek Solar LLC ("PPA").

The application clearly demonstrates that over a broad range of possible fossil-fuel price forecasts that their existing fossil fuel generation is likely unable to generate energy at costs less than the non-fossil fuel generation sources (including the revenue from REC sales) for the remaining 25 percent of the PPA over its 20-year life. As shown in Mr. Sinclair's testimony, the variable cost of energy produced by Companies' fossil-fuel generation facilities is higher than that from non-fossil fuel generation facilities (including the revenue from REC sales). The cause of the higher cost is the fossil fuel used for generation plus its associated variable O&M. As a result, the Companies cannot meet their remaining customers' demand for the lowest cost energy and satisfy their obligation to procure energy at the lowest reasonable cost without entering the PPA.

b. In the case of the proposed PPA as well as the Companies' continuing efforts to purchase economy power, the purchase of this energy does not require the retirement or placement into a standby status of existing generation. The maximum amount of energy that may be acquired under the proposed PPA represents less than one percent of the Companies' present annual generation. The acquired energy is intermittent, not firm power. However, the Companies' obligation to procure energy at the lowest reasonable costs may in some circumstances require the Companies to retire or place in a standby status existing generation resources if these resources are economically inefficient and are no longer necessary to ensure system reliability or meet peak demand and more economical and lower costing sources of energy are available.

c. The premise to the request for confirmation is unreasonable. Please see the response to AG 2-1(b). The maximum amount of energy that may be acquired under the proposed PPA represents less than one percent of the Companies' present annual generation and does not require any of the Companies' existing generation to be retired or placed in a standby status or "mothball" status.

d. The premise to the request for confirmation is unreasonable. KRS 278.030(2) requires the Companies to "furnish adequate, efficient and reasonable service." Accordingly, the Companies must have sufficient capacity available at all times to meet peak demand to ensure reliable and continuous service to their customers. Regardless of whether a unit is placed into service on a particular day, the Companies incur expenses to maintain that unit in the appropriate state of readiness as well as fixed costs, such as depreciation, related to that unit. These costs are reflected in base rates. These costs will be incurred regardless of whether the proposed PPA is approved and implemented. To the extent that the consumption of higher-cost fossil fuel can be avoided through the purchase of lower cost renewable energy, the Companies achieve a reduction in their variable costs of production that are promptly passed on to their ratepayers through the fuel adjustment clauses in the form of a lower fuel charge. The Companies have clearly stated in the application that no generation assets will be retired as a result of the Solar Power Contract (e.g., Sinclair testimony beginning at page 12, line 16).

e. The mechanics for making off-system sales requires that transactions be executed and transmission scheduled 20 minutes before the hour in which the energy will flow. Therefore, in order to make off-system sales related to solar generation would require the Companies to forecast solar generation from 20 minutes to 80 minutes ahead, i.e., the Companies would need to be able to forecast cloud formation. At this time, other than crystal clear days (which are few in KY), the Companies do not have the ability to forecast solar production to the degree necessary to make off-system sales.

   The proposed PPA is not an agreement for the purchase of firm power, but of intermittent energy and thus does not have operational capacity or dispatchability. The Companies are not assured of the timing or quantity of power to be provided. The production of the solar generation facility's energy is subject to when the sun shines and is not controllable. The quantity of energy obtained through the PPA will vary with weather and the time of the year. Given the nature of the purchased energy, the PPA does not make additional generation capacity available for off-system sales. While additional economic power sales may be possible because of the PPA, the likely volume of such sales is very difficult to predict. Pursuant to the Companies' Off-System Sales Adjustment Clause, 75 percent of the margins from such sales will be promptly passed on to the Companies' ratepayers.

f. The only generation assets that are fully depreciated are Paddy's Run 11 & 12. These are two secondary simple cycle gas turbines with a summer rating of 12 MW and 23 MW, respectively, that are rarely used due to their relatively high variable operating costs.

g. Confirmed. All of the Companies' generation assets are used and useful. While each of these assets exists is to ensure system reliability and continuous service, however, each has a defined function and are not necessarily interchangeable. For example, peaking units are designed and used to meet peak demands and serve a different purpose than base-load generation units.

   The purpose and function of the existing generation assets are not comparable to the purchase of the intermittent energy under the proposed PPA.

   The proposed PPA in no way diminishes the used and usefulness of the Companies' generation assets. The existing fossil fuel generation is unable to generate energy at costs less than the non-fossil fuel generation sources for the remaining 25 percent of the PPA because of the cost of fossil fuel used for generation.

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Dated March 17, 2020

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Question No. 2

Witness: David S. Sinclair

Q-2. In the event the Commission approves the proposed PPA, explain where the power generated under the PPA would fall within the Companies' order of economic dispatch of all existing generating units.

A-2. As can be seen in Article 7.2(A) of Exhibit 1 (Solar Power Contract) of the Application, "Scheduling shall be on a "must-take" basis, except to the extent that the Solar Energy Output of the Facility is reduced as a result of Forced Outages, Schedule Maintenance Outages, Additional Maintenance Outages, Force Majeure events and Emergency Conditions." Thus, the energy will be not be dispatched. As such, for the after-the-fact billing system, the energy will be placed at the bottom of the dispatch stack in the same manner as the generation from Ohio Falls, Dix Dam, and Brown Solar.

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Dated March 17, 2020

Case No. 2020-00016

Question No. 3

Witness: Counsel

Q-3. Confirm that the Companies' application at p. 8, paragraph no. 16 states: "Where an electric utility seeks to acquire additional energy through a power purchase agreement, the Commission has equated the purchase with the construction of additional generational facilities and has found that the same standard used to review the construction of generation facilities should be used to review the power purchase agreement, namely **whether a need for the additional generation capacity exists** and whether the purchase will result in a wasteful duplication of facilities." [emphasis added]

a. Confirm that fuel costs are not the sole dispositive factor as to whether the Commission should approve the instant application.

b. Explain where the need for additional generation capacity exists, as highlighted in the above quote.

A-3. The portion of the Companies' Application referenced in Request for Information discusses the standard that the Commission applied to prior applications for authorization to enter purchase power agreements. The sentence does not reflect the complete legal position of the Companies in this case for meeting the requirements in KRS 278.300. For a complete statement of the Companies' legal position in this case, please see the March 23, 2020 supplemental response to PSC 2-1.

a. Kentucky's then highest court observed in *Kentucky Utilities Company v. Public Service Commission*, that the construction of utility facilities providing capacity beyond present or expected demand may be a more efficient use of resources and not a wasteful duplication of facilities:

> An inadequacy of service might be such as to require construction of an additional service facility to supplement an inadequate existing facility, yet the public interest would be better served by substitution one large facility, adequate to serve all the consumers, in place of the inadequate existing facility, rather than constructing a new small facility to supplement the existing small facility. A supplementary small facility might be constructed that would not create duplication from the standpoint of an excess of capacity, but would result in duplication from

> the standpoint of an excessive investment in relation to efficiency and a multiplicity of physical properties.

Id. at 890. According to the Court in *Kentucky Utilities Company,* the determinative factor is the proposed facilities' effect on the utility's cost to deliver electric service and how that cost compares with other alternatives. As evidenced by almost countless, prior Commission decisions, Kentucky uses a "least-cost" standard when reviewing the merits of any utility request for approval of any new electric power source to serve its ratepayers"). In the present case, as demonstrated in the Resource Assessment presented in the direct testimony of David Sinclair, the cost of the energy acquired under the PPA (including revenue from the sale of RECs) is expected to be less than currently available energy from the Companies' existing fossil fuel generation facilities and should be the least cost source over the PPA's term.

b. The Companies object to the selective manner in which this Request for Information has taken the quoted section of the Application out of context. For reasons set forth in great detail in the Companies' Supplemental Response to PSC 2-1, the proposed purchased power agreement with Rhudes Creek Solar LLC ("PPA") is not for the acquisition of generation capacity nor is it equivalent to the construction of new generation facilities. Accordingly, it is not subject to the analysis set forth in *Kentucky Utilities Company v. Public Service Commission*, 252 S.W.2d 885 (Ky. 1952), which Kentucky courts and the Commission use to determine whether a CPCN should be issued.

If *Kentucky Utilities Company* analysis is applicable, the PPA clearly satisfies its requirements. In *Kentucky Utilities Company* the Kentucky Court of Appeals declared that an applicant for a certificate of public convenience and necessity must demonstrate a need for the new facilities and the absence of wasteful duplication. *Id.* at 890. To demonstrate need, an applicant must show a "substantial inadequacy" of existing facilities great enough "to make it economically feasible for the new system or facility to be constructed and operated." *Id.* It must also show that the inadequacy is due to "a substantial deficiency of service facilities beyond what would be supplied by normal improvements in the ordinary course of business." *Id.* As demonstrated in their Supplemental Response to PSC 2-1, the Companies have made such a demonstration. The Companies' efforts to continue to identify methods for achieving a lower cost for their customers is in complete accord with the Commission's longest-standing policy of operating at the least cost when reasonably possible.

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Question No. 4

Witness: David S. Sinclair

Q-4. Reference the response to PSC 2-1, wherein it is stated, "Even though the utility has generation capacity to meet customer demand, it is more economical and more beneficial to its ratepayers if it purchases the energy rather than use its existing generation assets."

a. Explain whether the statement that it would be more economical takes into consideration the all-in costs attendant with continuing to operate all existing generating units, even when the Companies are receiving power under the proposed PPA. If not, provide an analysis of the all-in costs that would continue to be incurred for the existing generating units, when the Companies accept power under the PPA.

A-4. It would be improper financial analysis to include the fixed costs of any asset when making a marginal utilization decision because fixed costs are not changeable in the short run, in this case every second. That is why economic dispatch of the existing generating fleet only looks at the variable cost of energy. Because the Solar Power Contract does not drive any retirements of existing generation assets, all existing fixed costs of the generation fleet will continue.

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Question No. 5

Witness: David S. Sinclair

Q-5. Reference the response to PSC 2-1, wherein it is stated, "'Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties.'"

a. Confirm that the proposed PPA would add additional capacity to the Companies' existing capacity.

A-5. Currently, it is the practice in the utility industry to assign a "capacity" value to variable energy resources such as solar that is based on the statistical likelihood of energy that will be produced at the forecasted time of system peak. However, since the date and time of system peak is uncertain as will be the sunlight and cloud conditions at that time, there is no way to really know what the output will be from a reliability planning perspective. Therefore, while the Companies will show a "capacity" value for the Solar Power Contract in its forecasted resource plan, the reliability value of this resource is not the same as a dispatchable resource.

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Question No. 6

Witness: David S. Sinclair

Q-6. Reference the response to PSC 2-5 (a). State when the ITO's transmission studies will be available. Will the Companies commit to making them available if and when they are completed? If not, explain why not.

A-6. The Generation Interconnection ("GI") Customer, Rhudes Creek Solar, submitted a Provisional Interconnection Service ("PRIS") request to LG&E/KU's Independent Transmission Organization ("ITO"), TranServ International, on March 11, 2020. PRIS provides generators a mechanism to interconnect a generating facility prior to the completion of the normal interconnection process (i.e., ITO studies and construction of any necessary network upgrade). The ITO will determine, through available or additional studies, whether issues would arise if the generator interconnects without modification to the Transmission System. If issues are identified that require upgrades, the generator may receive limited service up to the amount of capacity that does not require network upgrades. Obtaining PRIS does not obviate a generator's requirement to follow the normal full interconnection process. An executive summary of the existing or additional study reports will be available publicly via the LG&E/KU OASIS site. The full reports will be available to anyone that has executed a non-disclosure agreement ("NDA") with LG&E/KU because of the full reports' inclusion of Critical Energy Infrastructure Information.

Based upon the posted timeline on LG&E/KU's Open Access Same-Time Information System ("OASIS"), LG&E/KU would expect the studies related to the PRIS request could be complete before the end of the year.

Importantly, completion and approval of PRIS or the normal generation interconnection process does not grant Transmission Service to transmit the power once the generator is interconnected. A separate Transmission Service Request ("TSR") must be submitted to the ITO and studied. LG&E/KU, as the Transmission Customer ("TC") may at any time submit the TSR. The required TSR studies will be completed approximately 90-180 calendar days after the TC submits the TSR to the ITO, depending up on necessary type of study(ies).

The Companies (as the TC) have not submitted a TSR to the ITO yet and are unlikely to do so unless and until the Commission approves the Solar Power Contact. Per Article 6.2(B), the Companies have until December 31, 2020 to procure transmission service. An executive summary of the TSR study reports will be publicly available via OASIS with the full reports available upon execution of an NDA.

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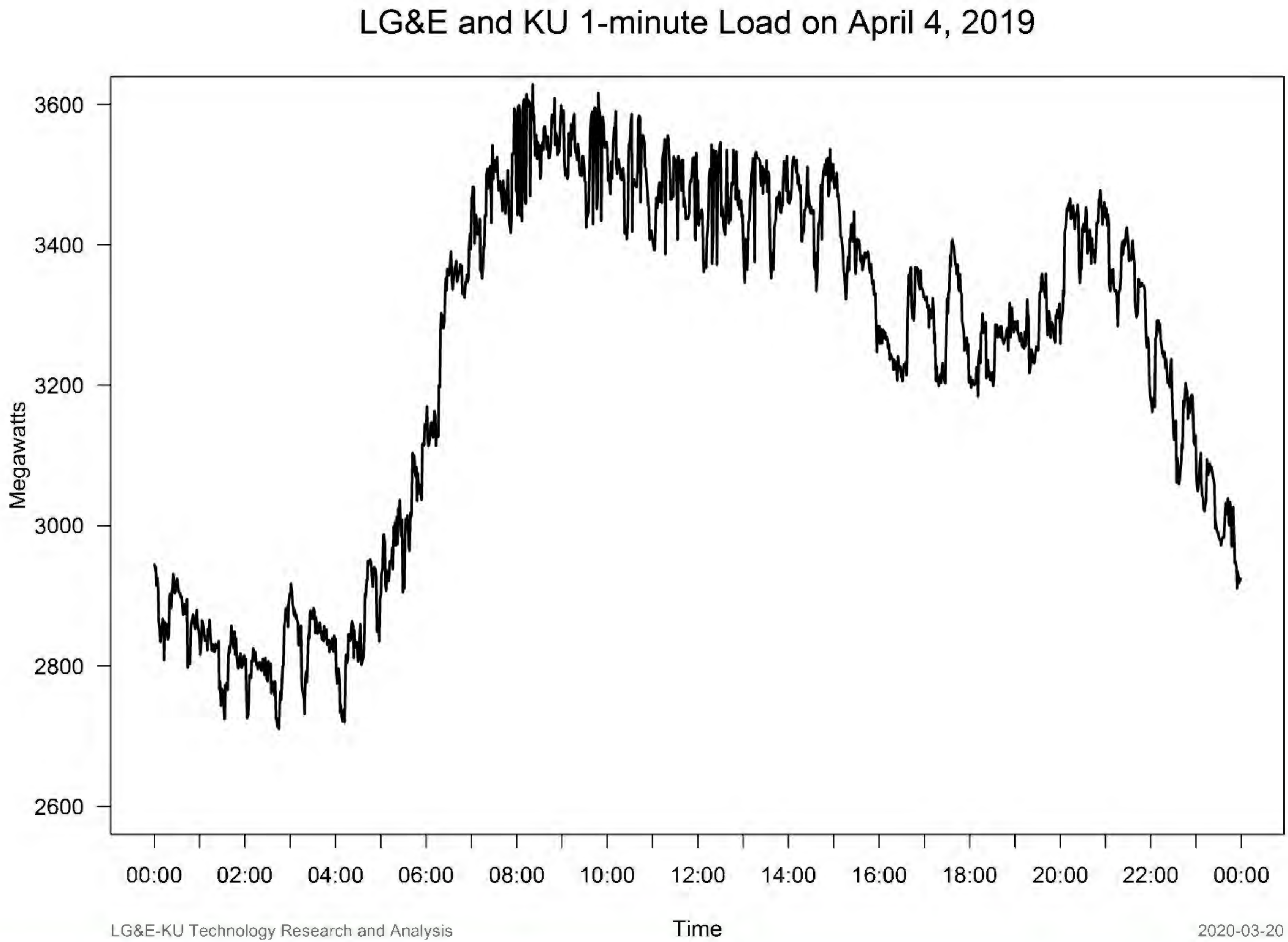
Question No. 7

Witness: David S. Sinclair

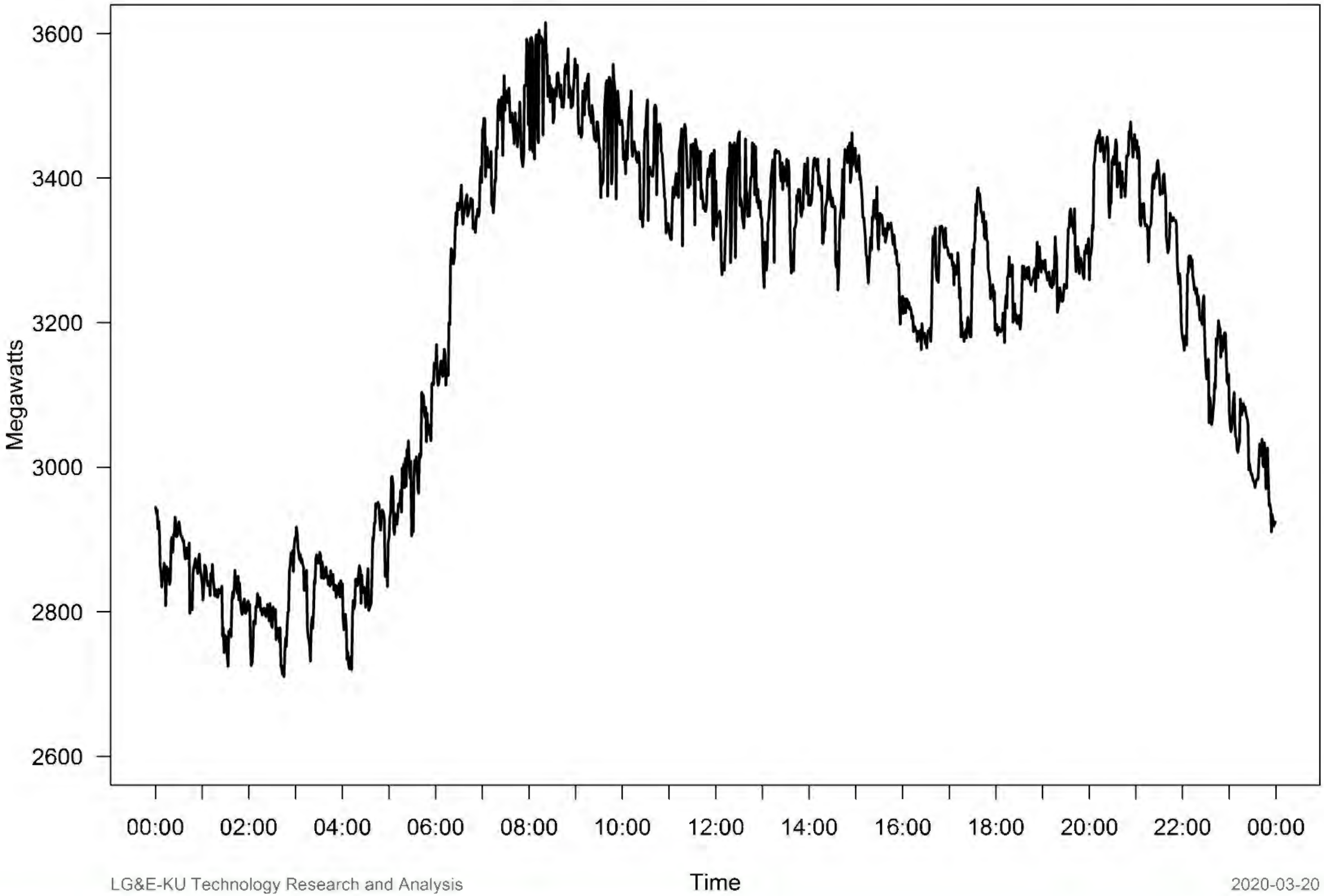
Q-7. Reference the response to AG 2-33 (a)(ii). In the event that the integration of energy from the solar PPA does lead to any discernable ramping changes for the Companies generation fleet, explain which customers would pay the attendant costs, and why.

A-7. The Companies have not identified, nor do they expect to identify, any integration cost for the solar PPA, which is expected to provide less than one percent of the Companies' annual generated energy and a small percentage of generation at any given moment. As demonstrated in Table 12 of Exhibit DSS-2, the energy from the solar PPA combined with the sale of RECs is expected to reduce overall costs for all customers. This savings is the result of the ability of the existing fossil fuel fleet to ramp up and down to accommodate the energy from the solar PPA. See also page 12, line 16 through page 13, line 3 of Mr. Sinclair's testimony.

It is important to understand that the Companies' generation fleet is designed to follow the moment-to-moment fluctuations in load that can easily be over 100 MW, even on relatively mild weather days. Page 1 of the attachment to this response shows the actual 1-minute load on April 4, 2019 to illustrate the nature of the system's real-time load volatility. Page 2 reduces this load by what would have been the actual output from a hypothetical 100 MW solar facility based on actual 1-minute solar irradiance data for that very same day. As one can see, there is virtually no difference in the 1-minute volatility of Page 1 and Page 2. This same conclusion would be true for any other day of the year.


LG&E and KU 1-minute Load on April 4, 2019
Megawatts
3600
3400
3200
3000
2800
2600
00:00
02:00
04:00
06:00
08:00
10:00
12:00
14:00
16:00
18:00
20:00
22:00
00:00
Time
LG&E-KU Technology Research and Analysis
2020-03-20

LG&E and KU 1-minute load less 100 MW of Solar Generation on April 4, 2019



Louisville Gas and Electric Company and Kentucky Utilities Company
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Dated March 17, 2020

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Question No. 8

Witness: Daniel K. Arbough

Q-8. Provide any analyses regarding whether rating agencies view PPAs that do not have a capacity component as an evidence of indebtedness.

A-8. In some situations, the rating agencies determine a contract to purchase power is a debt-like obligation, and, consequently, impute debt to the buyer's balance sheet. However, the Companies do not believe the proposed PPA will be treated as a debt-like obligation by the rating agencies, and do not expect any imputed debt to result from the execution of the PPA.

Moody's Investor Services ("Moody's") and S&P Global Ratings ("S&P") both have published articles detailing how they treat power purchase agreements. Moody's perspective is shown on page 42 of Attachment 1. In the first paragraph Moody's states, "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." As noted previously, the PPA does not contain a capacity payment, but includes only an energy charge that is due based upon the number of MWh produced by the solar plant. The costs of the 25 MW used to benefit all customers under the PPA, if approved, would be recovered by the Companies through the Fuel Adjustment Clause ("FAC") pursuant to 807 KAR 5:056, Section 1(3)(c), as economy energy purchases. On page 43 of Attachment 1 in the paragraph entitled "Pass-through capability", Moody's states that if the costs are recovered via a pass-through such as the FAC, "we regard these PPA obligations as operating costs with no long-term debt-like attributes." The 75 MW dedicated to Toyota and Dow would be treated in a similar way because the costs are directly recovered via the RPAs.

S&P's guidance is substantively comparable to Moody's, but is addressed in the two documents attached as Attachments 2 and 3. On page 32 of Attachment 2, S&P indicates it may determine a percentage of the present value of the purchase power to be a debt equivalent using an analytically determined risk factor. While the details are not shown in the most recent publication, S&P previously provided additional transparency in Attachment 3 in paragraph 58 on page 14. S&P states, "We calculate the present value ("PV") of the future stream of capacity payments under the contracts…". In the case of the subject PPA, the PV would be zero due to the absence of capacity payments.

Based on the discussion above, the Companies do not expect the rating agencies to impute any debt to their balance sheets as a result of the PPA. Therefore, the PPA will not be a long-term burden to the balance sheet nor represent a cost burden to ratepayers.

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MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

Table of Contents:

Analyst Contacts:

NEW YORK +1.212.553.1653

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
Managing Director – Utilities
james.hempstead@moodys.com

Walter Winrow +1.212.553.7943
Managing Director - Global Project and Infrastructure Finance
walter.winrow@moodys.com

Jeffrey Cassella +1.212.553.1665
Vice President - Senior Analyst
jeffrey.cassella@moodys.com

Natividad Martel +1.212.553.4561
Vice President - Senior Analyst
natividad.martel@moodys.com

» contacts continued on the last page

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

Summary

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

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

THIS RATING METHODOLOGY WAS UPDATED ON NOVEMBER 4, 2019. WE HAVE UPDATED SOME OUTDATED REFERENCES AND ALSO MADE SOME MINOR FORMATTING CHANGES.

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

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

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

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

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

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

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the scorecard factors

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the scorecard

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

This methodology describes the analytical framework used in determining credit ratings. In some instances, our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities.[2]

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

About the Rated Universe

This methodology applies to rate-regulated[3] electric and gas utilities that are not Networks[4]. Regulated electric and gas utilities are companies whose predominant[5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

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

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

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: regulated networks, unregulated utilities and power companies, public power utilities, municipal joint action agencies, electric cooperatives, regulated water companies and natural gas pipelines.[6]

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

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

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

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

About this Rating Methodology

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

1. Identification and Discussion of the Scorecard Factors

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

Factor / Sub-Factor Weighting - Regulated Utilities

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

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

2. Measurement or Estimation of Factors in the Scorecard

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

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the scorecard. However, the factors in the scorecard can be assessed using various time

[7] For more information, see our cross-sector methodology that describes our standard adjustments in the analysis of non-financial corporations. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve-month periods.

3. Mapping Scorecard Factors to the Rating Categories

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

4. Assumptions Limitations and Rating Considerations Not Included in the Scorecard

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

5. Determining the Overall Scorecard-Indicated Outcome[8]

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

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

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

Scorecard-Indicated Outcome

Scorecard-Indicated Outcome	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5

8 In general, the scorecard-indicated outcome is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the scorecard-indicated outcome is oriented to the baseline credit assessment. For more information, see our cross-sector methodology that describes our general approach for assessing government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. For more information, see our cross-sector methodology that describes principles related to loss given default for speculative grade non-financial companies and also our cross-sector methodology that describes the alignment of corporate instrument ratings based on differences in security and priority of claim. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

Scorecard-Indicated Outcome

Scorecard-Indicated Outcome	Aggregate Weighted Total Factor Score
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

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

6. Appendices

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

Discussion of the Scorecard Factors

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

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

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

Factor 1: Regulatory Framework (25%)

Why It Matters

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

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary

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

that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

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

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

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

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

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

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

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

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

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

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

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

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

How We Assess Consistency and Predictability of Regulation for the Scorecard

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

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

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

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

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

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

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

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

Why It Matters

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

How We Assess Ability to Recover Costs and Earn Returns

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

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

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

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

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

How We Assess Sufficiency of Rates and Returns for the Scorecard

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

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

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

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

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

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

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

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

Factor 3: Diversification (10%)

Why It Matters

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

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

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

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

How We Assess Market Position for the Scorecard

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

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources.[10] We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that

[10] For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com.

has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

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

How We Assess Generation and Fuel Diversity for the Scorecard

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

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

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

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges.

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

Factor 4: Financial Strength (40%)

Why It Matters

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

How We Assess It for the Scorecard

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[11], 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[12]. 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 C) 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

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

12 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 scorecard 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[13]. 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[14] 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 scorecard-indicated outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Scorecard-indicated outcomes 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[15]

» 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:

[13] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[14] 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.

[15] 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 scorecard may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the scorecard 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.

Assumptions, Limitations and Other Rating Considerations

The scorecard in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the scorecard to map more closely to actual ratings. Accordingly, the four factors and the notching factor in the scorecard 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 scorecard is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot 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 scorecard, 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 scorecard 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 scorecard without making the scorecard 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 scorecard.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the scorecard. 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 have been swift to cut or defer discretionary spending during recessions. 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 scorecard 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. 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 scorecard 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 scorecard.[16]

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 scorecard-indicated outcomes 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

[16] For more information, see our cross-sector methodology that discusses general principles related to how sovereign credit quality can impact other ratings. A link to an index of our sector and cross-sector methodologies can be found in the "Moody's Related Publications" section.

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 Scorecard

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.

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

Factor 4: Financial Strength

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

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

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

General Approach to a Utility Family

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

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

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

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

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

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

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

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

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

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

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

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

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

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

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

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

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

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix D: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

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

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

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

Securitization

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

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

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

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

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

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

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

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

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

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

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

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

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

Additional considerations for PPAs

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

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

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

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

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

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

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

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

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

Methods for estimating a liability amount for PPAs

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

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

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

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

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

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

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

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

Moody's Related Publications

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

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

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

» contacts continued from page 1

Analyst Contacts:

BUENOS AIRES	+54.11.5129.2600

Daniela Cuan +54.11.5129.261
Vice President - Senior Analyst
daniela.cuan@moodys.com

TORONTO	+1.416.214.163

Gavin MacFarlane +1.416.214.386
Vice President - Senior Credit Officer
gavin.macfarlane@moodys.com

LONDON	+44.20.7772.545

Douglas Segars +44.20.7772.158
Managing Director - Infrastructure Finance
douglas.segars@moodys.com

Helen Francis +44.20.7772.542
Vice President - Senior Credit Officer
helen.francis@moodys.com

HONG KONG	+852.3551.307

Vivian Tsang +852.375.815.3
Associate Managing Director
vivian.tsang@moodys.com

SINGAPORE	+65.6398.830

Ray Tay +65.6398.830
Vice President - Senior Credit Officer
ray.tay@moodys.com

TOKYO	+81.3.5408.410

Mihoko Manabe +81.354.084.033
Associate Managing Director
mihoko.manabe@moodys.com

Mariko Semetko +81.354.084.20
Vice President - Senior Credit Officer
mariko.semetko@moodys.com

Report Number: 1072530

Author
Michael G. Haggarty

Production Associate
Masaki Shiomi

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S&P Global Ratings

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Guidance | Criteria | Corporates | General:

Corporate Methodology: Ratios And Adjustments

April 1, 2019

Overview And Scope

1. This document provides additional information and guidance relating to the application of S&P Global Ratings' "Corporate Methodology: Ratios And Adjustments" criteria published April 1, 2019. This guidance document is intended to be read in conjunction with that criteria. For further explanation on guidance documents, please see the description at the end of this document.

Guidance

2. Our analytical adjustments are not generally affected by ongoing changes in accounting rules, but we may modify our analytical adjustments for a significant rule change to ensure our adjusted metrics remain consistent across accounting standards.

3. Where financial information required for our analytical adjustments is not provided, we may request it from management or otherwise determine a best estimate.

4. **Sufficiently creditworthy:** For the purpose of our criteria, we would consider a company to be sufficiently creditworthy if it is rated in the investment-grade category (i.e. 'BBB-' or higher).

5. **Nonrecurring items and pro forma figures:** The relative stability or volatility of a company's earnings and cash flow is an important measure of credit risk that is embedded in our corporate methodology. For this reason, our use of nonrecurring or pro forma adjustments is typically limited to when there has been some transformational change in a company's business. A transformational event is one that causes a material change in an entity's business or financial profile. Examples include the divestment of part of the business or a fundamental change in operating strategy.

Key Publication Information

- Original publication date: April 1, 2019.
- This article is related to "Corporate Methodology: Ratios And Adjustments," published April 1, 2019.

ANALYTICAL CONTACTS

Leonard A Grimando
New York
(1) 212-438-3487
leonard.grimando@spglobal.com

Imre Guba
Madrid
(44) 20-7176-3849
imre.guba@spglobal.com

Sam C Holland, FCA
London
(44) 20-7176-3779
sam.holland@spglobal.com

Shripad J Joshi, CPA, CA
New York
(1) 212-438-4069
shripad.joshi@spglobal.com

Raam Ratnam, CFA, CPA
London
(44) 20-7176-7462
raam.ratnam@spglobal.com

Scott E Zari, CFA
Chicago
+ 1 (312) 233 7079
scott.zari@spglobal.com

See complete contact list at end of article.

6. **Discontinued operations and business divestments:** We typically exclude profits, losses, and cash flows from discontinued operations from our metrics so that they more accurately reflect the company's ongoing operations.

7. **Pro forma accounts for intrayear acquisitions or irregular reporting periods:** If an acquisition has occurred, the financial statements for the year of the acquisition include all of the enlarged group's debt in the year-end balance sheet, but less than the acquired company's full-year results and cash flows. Depending on the acquired company's size, this can distort debt coverage ratios, which therefore may not accurately indicate the company's likely future performance. A similar issue exists when companies have irregular accounting periods, such as after a change in their accounting year end. In these cases, we may use pro forma financial statements to allow for a more representative measure of full-year performance and more meaningful ratios.

Scope of consolidation

8. When analyzing a group's creditworthiness, a first critical step is to determine how the results of subsidiaries and affiliates should be depicted in the parent's consolidated financial statements. This determination builds on our view of the group, including the relationship of the parent with its subsidiaries, as per our group rating methodology.

9. There are several accounting methods to reflect a company's relationship with another company (treating it as an investment, accounting for it under the equity method, fully consolidating it, etc.). Most often we use the same scope of consolidation as is used in the parent's consolidated financial statements. This is because accounting consolidation and the underlying analytical principle of our group rating methodology both rely on the concept of "control," which refers to the parent's ability to dictate a group member's strategy and cash flow.

10. Several factors determine our analytical view of a company's relationship with a particular subsidiary or affiliate. These factors include strategic importance, whether there is control, percentage of ownership, likely financial support, and whether there are other owners, and if so what rights those other owners have. The parent company's ability to control, direct, and benefit from the subsidiary's cash flows may also drive our decision on whether to accept the accounting consolidation.

11. Based on the above analysis, we may adjust the group's financial statements to better reflect our opinion of the underlying economic drivers of a company's business and financial ties with its subsidiaries or affiliates and the resulting benefits and obligations. We may also adjust the group's financial statements if the group includes businesses with very different business models and credit drivers. For example, we may deconsolidate the regulated banking operations of a retail parent to better understand, analyze, and reflect the credit quality of the two separate businesses, even though we may consider both to be part of the same wider group, and we will treat them as per our group rating methodology.

12. In certain cases, full consolidation used in the financial statements may not reflect our view of the group's real underlying leverage or controlled cash flows due to significant minority shareholders in the subsidiaries. In these cases we will use other consolidation methods (such as proportionate consolidation) to estimate key credit metrics.

Adjustments For Key Principles

13. We apply four key principles in our adjustments to reported financial data: the adjusted debt, adjusted earnings, adjusted cash flow, and adjusted interest principles. The summary tables under each section of our key principles illustrate the routine adjustments for each one. Additionally, we may apply situational and sector-specific adjustments in each calculation.

Adjusted debt principle

14. We calculate adjusted debt as follows:

	Reported debt
-	Accessible cash and liquid investments
+	Leases
+	PRBs and deferred compensation
+	AROs
+	Securitization, sale, and factoring of trade receivables and other assets
+/-	Hybrid capital instruments
+	Financial guarantees
+	Earn outs and deferred consideration for business acquisitions
	Adjusted debt

15. We typically measure certain long-term liabilities that do not bear explicit interest payments by calculating the net present value of the liabilities using a discount rate. For instance, minimum non-cancellable operating lease commitments are discounted at 7% for companies that do not capitalize operating leases on the balance sheet. For other liabilities, such as bonds or loans that pay interest, the amortized cost basis of measurement captures the discounting impact of the debt principal.

16. **Adjustment to debt for non-executory contracts:** We may treat as debt certain non-executory contracts such as take-or-pay contracts. In certain situations, these contracts provide benefits of future price protection to the buyer in exchange for an unconditional minimum purchase obligation to the seller. This is primarily because the seller takes on much of the price risk and non-performance risk by the buyer.

17. **Adjustment to debt for redeemable common stock held by minority shareholders:** We add the liability derived from a redeemable minority interest when the redemption is outside of the issuer's control (for example, the minority interest holder has a put option on the subsidiary's shares as opposed to the issuer having a call option to repurchase the shares) and we fully consolidate the subsidiary in our analysis. The liability would be added to our adjusted debt figure based on the adjusted debt principle since the subsidiary is fully consolidated in our metrics and, therefore, the benefits of ownership are accruing to the issuer. We may take a different view depending upon the facts and circumstances if we judge that the option is very unlikely to be exercised.

18. **Structured settlements of dispute:** We include in adjusted debt (on a discounted basis if feasible) liabilities related to structured settlements of dispute, whether with commercial or governmental entities. For example, we add tax and tobacco settlements to debt because they are "incurred liabilities that provide no future offsetting operating benefit."

19. **Shares other than common stock** We will not add classes of shares to our adjusted debt measures, regardless of their denomination, if they will never require any cash payments or cause any credit stress and if they comply with all of the following conditions:

- No stated coupon or yield;
- No maturity;
- No ability to redeem for cash (but could be converted into common stock);
- No covenants or events of default;
- No security or guarantees; and
- Subordination to all debt.

20. This provision would also apply if shares that comply with all of the above characteristics also include one or both of the following:

- A preference in liquidation to other common stock; and/or
- A preference in the distribution of dividends when dividends are declared, but no entitlement to dividends otherwise. This would be the case, for example, if when dividends are declared there is an agreement among shareholders about how those dividends are distributed. We would not include in this provision shares that carry a dividend that can be deferred, whether cumulative or non-cumulative. These instruments are typically covered by our hybrid criteria.

21. However, we will add to our adjusted debt measures shares that are subject to a put option or other economically similar mechanism (except if the put option can only be exercised upon an initial public offering).

22. Shares other than common equity provided by controlling shareholders should be analyzed under our non-common equity financing criteria.

Adjusted earnings principle

23. We calculate adjusted EBITDA as follows:

	Reported revenue
-	Operating expenses
+	Depreciation
+	Amortization
+	Non-current asset impairment and impairment reversals
+	Cash dividends received from equity accounted affiliates (we exclude the profits or losses from such affiliates)
+	Equity settled stock compensation
-	Capitalized development costs
+	Adjustments for leases
+/-	Adjustments for PRBs and deferred compensation

-	Adjustments for AROs
+/-	Adjustments for earn outs and deferred consideration for business acquisitions
	Adjusted EBITDA

24. We calculate adjusted funds from operations (FFO) as follows:

	Adjusted EBITDA
-	Cash interest paid, adjusted
-	Cash taxes paid
	Adjusted FFO

Operating and non-operating items

25. Our calculation of EBITDA and FFO generally includes items that we consider to be operating in nature (rather than investing or financing in nature) and excludes non-operating items. Most often, our view is consistent with how accounting standards classify these items in the statement of cash flows. Below are examples of how we apply our adjusted earnings principle to various scenarios to determine whether transactions are operating or non-operating. The adjustments below are routinely made to all companies where applicable and material.

26. **Disposals:** We typically view the disposal of a subsidiary or the sale of property, plant, and equipment as outside core business operations. As such, we generally do not treat these transactions as an operating activity and exclude any gain or loss from our calculation of EBITDA and FFO.

27. **Restructuring costs:** Our calculation of EBITDA typically includes restructuring costs (which reduce EBITDA), including those that will be settled in cash in the future. We typically view restructuring costs as an operating item because most companies need to restructure their operations to adapt to changing environments and remain competitive and viable.

28. **Acquisition-related costs:** Our EBITDA calculation includes acquisition-related costs including advisory, legal, and other professional and administrative fees related to an acquisition. Many businesses make acquisitions as part of their growth strategy; therefore it is important to factor these expenses into EBITDA.

29. **Asset impairments/write-downs:** We exclude impairment costs or reversals on tangible and intangible noncurrent assets from our definition of EBITDA because they are akin to depreciation or amortization costs in that they represent a company's income statement recognition of earlier capital expenditures. However, we include impairment costs on current assets, such as inventory and trade receivables because the charges for inventory represent a company's recognition in the income statement of money that it has already spent, and those for trade receivables represent the reduction of revenue and income previously recognized but that the company will not fully collect. Our definition of EBIT generally includes impairment charges or reversals, except we may adjust for very large and irregular impairments or impairment reversals of non-current assets.

30. **Foreign currency transaction gains and losses:** We may view foreign currency transaction gains and losses as operating (and therefore include them in EBITDA and FFO) or non-operating in nature. For example, if material, we exclude foreign currency gains or losses resulting from the

issuance of foreign currency-denominated debt from EBITDA and FFO if those gains or losses are shown as operating items.

31. **Unrealized fair value movements:** When disclosed, we typically reverse the impact of unrealized fair valuation gains and losses from EBITDA and FFO. Examples of these items include:

- Unrealized fair valuation gains or losses on investment properties under International Finance Reporting Standards (IFRS);
- Changes in value of earn-out liabilities; or
- Unrealized gains and losses on derivatives.

Adjusted cash flow principle

32. We calculate adjusted cash flow from operations (CFO), adjusted free operating cash flow (FOCF), and adjusted discretionary cash flow (DCF) as follows:

	Reported CFO
+/-	Interest or dividends received and interest paid reported outside of CFO
-	Capitalized interest
-	Capitalized development costs
+/-	Adjustments for securitization, sale, and factoring of trade receivables and other assets
+/-	Adjustments for leases
+/-	Adjustments for hybrid capital instruments
+/-	Adjustments for earn outs and deferred consideration for business acquisitions
	Adjusted CFO
-	Adjusted capital expenditures
	Adjusted FOCF
-	Cash dividends (paid on common and preferred stock)
-	Share buybacks
	Adjusted DCF

33. Capital expenditures include funds spent to acquire or develop tangible and intangible assets. We make adjustments to reported capital expenditures for capitalized development costs and capitalized interest.

Adjusted interest principle

34. We calculate adjusted interest as follows:

	Reported interest expense on gross financial debt*
+	Amortization of discounts on debt issuance fees
+	Non-cash interest on conventional debt instruments (plus any interest on hybrid capital instruments, shareholder loans, and non-common equity)
+	Capitalized interest

+	Lease interest
+	PRB interest
+	ARO interest
+	Realized effects of interest hedging derivatives
-	Unrealized fair value movements of interest derivatives
	Adjusted interest expense

Note: In our calculation of adjusted interest expense + or - indicates that we include or exclude items that may or may not already be reflected in the reported interest expense.

35. Our adjusted interest principle is based on an accrual-based interest expense and is primarily used to calculate the EBITDA-to-interest coverage ratio. However, we use the reported cash interest plus or minus applicable adjustments to calculate FFO cash interest coverage.

Routine Analytical Adjustments

Accessible cash and liquid investments

36. We identify cash and liquid investments as inaccessible when, for example, they are:

- Held in a nonconvertible currency to the currency of a company's borrowings;
- Subject to distribution restrictions (for example, cash and investments held in escrow, unless they are restricted to support obligations that we include in debt);
- Trapped in subsidiaries (as we believe that cash may not be moved out of the subsidiary at short notice to repay debt elsewhere in the group; however, cash at a subsidiary that meets our criteria for netting may be netted against adjusted debt at that subsidiary);
- Required to fund tax payable on repatriating cash or liquidating an asset; or
- Held specifically on behalf of third parties (such as governments, customers, etc.).

37. In addition, we will assess whether there are risks of exchange or capital controls in the company's home country, or in the country or countries where its subsidiaries are located, that should be reflected in the calculation of accessible cash.

38. We will generally not deduct accessible cash and liquid investments (accessible cash) from debt if a company is owned by a financial sponsor or has a business risk profile assessment of weak or vulnerable (both concepts defined in our "Corporate Methodology"). However, we deduct accessible cash from debt even if a company meets either of these conditions, as long as:

- We believe that the company has accessible cash ear-marked to retire maturing debt or other debt-like obligations; and
- We believe--typically from the company's track record, market conditions, or financial policy--that management will use the cash to pay off maturing debt or debt-like obligations.

39. Cash held in escrow for the debtholders' benefit would be fully netted off from debt if the debt is included in our debt calculation.

40. When calculating accessible cash, we typically do not reduce cash and liquid investments by the amount of expected working capital investment needs. This is because this would disadvantage

companies that fund working capital from cash rather than by drawing down on bank lines.

41. In rare cases, we may exclude from accessible cash unusually large portions of cash physically trapped in the usual course of business. Some examples of this include a supermarket that has an unusually large amount of "cash in tills," or a casino that has a higher-than-typical amount of "cash in cages."

42. Data requirements:

- The amount, term, location, liquidity, and other characteristics of accessible cash.

43. Calculation:

- Debt: We reduce debt by the amount of accessible cash.

Leases

44. We generally accept the balance sheet treatment for companies that capitalize all leases on their balance sheet, such as U.S. Generally Accepted Accounting Principles (GAAP) and IFRS filers, by including the reported lease obligations in our adjusted debt. In certain circumstances we may adjust the amount added to adjusted debt to better reflect the lease leverage (see below).

45. For U.S. GAAP filers that capitalize all leases, we also adjust our income statement and cash flow measures to remove the distinction between finance leases and operating leases.

46. For those entities not required to capitalize operating leases on balance sheet, we will adjust our debt, earnings, interest, and cash flow measures for operating lease reporting. To calculate the adjustment to debt for operating leases that are not reported on balance sheet, we calculate a present value of the future lease payments using a 7% discount rate. We may update our discount rate in the future based on data and trends observed from entities that have reported operating leases on their balance sheets.

47. We net sublease rental income from future lease payments only if the lease and sublease terms match and we believe the holder of the sublease is sufficiently creditworthy (as previously defined).

48. We do not adjust capital expenditures, and therefore FOCF, for any implied capital expenditures relating to leases.

49. **Leases with artificially short terms** In certain cases we may adjust the lease amount added to our measure of debt to better reflect the lease leverage, for example if we view the remaining lease terms as artificially short relative to the expected use of the leased asset. Our expectation is that, in most cases, the reported lease liabilities should be at least three times the next 12 months' lease commitments. If they're below this level, we may increase the reported lease liabilities to at least three times and reflect that impact in the other metrics affected by the lease adjustment.

50. The three times multiple is not a hard measure, and analytical judgment is applied. We may increase the liability above three times in certain instances, such as to enhance comparability in lease-intensive sectors. Further investigation may indicate that no upward adjustment is required. For example, if a company's only significant lease--with a remaining lease term of two years--was for a non-core asset that would not be needed after two years due to a change in the company's business model, then no upward adjustment would be necessary.

51. **Other lease-like contracts** In rare cases, we also adjust lease liabilities (such as when companies characterize lease contracts as service contracts), because we believe the reported amounts do not adequately capture the transaction's underlying economics. In such cases, we may also carry

through this adjustment to our other metrics, if appropriate.

52. Data requirements:
For IFRS companies for which IFRS 16 is adopted:

- Reported lease obligations on the balance sheet (both the current and noncurrent portions)

For U.S. GAAP companies for which ASC Topic 842 is adopted:

- Reported finance lease obligations on the balance sheet (current and noncurrent portions).
- Reported operating lease obligations on the balance sheet (current and noncurrent portions).
- Reported operating lease cost for the most recent income statement.
- Reported weighted average operating lease discount rate.

For companies that have not yet adopted or do not report under the above lease accounting standards:

- Minimum lease payments: The schedule of non-cancellable future lease payments over the next five years and beyond.
- Reported finance lease obligations on the balance sheet (current and non-current portions).
- Reported annual lease-related operating expenses for the most recent year.
- The annual operating lease-related expense, which we estimate using the average of the first projected annual payment disclosed at the end of the most recent year and the previous year.

53. Calculations:
For IFRS companies for which IFRS 16 is effective:

- Debt: We include the reported amount of lease obligations in adjusted debt.
- Interest expense: We reclassify any lease interest as an operating cash flow under IFRS if it is presented as part of the investing or financing section of the statement of cash flows.

For U.S. GAAP companies for which ASC Topic 842 is effective:

- Debt: We include the reported amount of lease obligations in adjusted debt.
- Income statement and cash flow measures: The reported operating lease cost is allocated to interest and depreciation expenses. EBITDA is increased by adding back the interest and depreciation expenses. EBIT is increased by adding back the interest expense. CFO is increased by adding back the depreciation expense (which we use as a proxy for the capital repayment portion of the lease). FFO is decreased by the operating lease interest expense (as a proxy for cash interest).
- Interest expense: The interest expense is increased by multiplying the average operating lease obligation for the current and previous year by the reported weighted average operating lease discount rate.
- Depreciation expense: The depreciation expense is increased by the difference between the reported operating lease cost and the calculated interest expense.

For companies that have not yet adopted or do not report under the above lease accounting standards:

- Debt: For operating leases, we add the present value of future lease payments to debt, calculated using a 7% discount rate. Since minimum lease payments beyond the fifth year are regularly disclosed in aggregate as "thereafter," our methodology assumes that annual payments beyond the fifth year equal the payment amount in year five, and that the number of years in the "thereafter" period equals the "thereafter" amount divided by the fifth-year amount, rounded to the nearest year. This assumption is capped at a total payment profile of 30 years.

- Debt: For finance leases, if they are not already included in reported debt, we add reported finance lease obligations to debt.
- Total assets: We add the amount of operating leases we reclassify as debt to total assets to approximate the depreciated asset cost.
- Income statement and cash flow measures: The lease-related expense is allocated to interest and depreciation expenses. EBITDA is increased by adding back the interest and depreciation expenses. EBIT is increased by adding back the interest expense. CFO is increased by adding back the depreciation expense (which we use as a proxy for the capital repayment portion of the lease). FFO is decreased by the operating lease interest expense (as a proxy for cash interest).
- Interest expense: The interest expense is increased by the product of the 7% discount rate multiplied by the average net present value of the lease payments for the current and previous year.

Postretirement employee benefits and deferred compensation

54. **Adjustments to debt** We include underfunded defined-benefit obligations for retirees, including pensions and health care coverage (collectively, PRB) in our measure of adjusted debt because they represent financial obligations that must be paid over time. Our calculation of PRB includes other forms of deferred compensation like retiree lump-sum payment schemes and long-service awards, but not defined-contribution obligations.

55. To calculate the amount we add to debt, we aggregate all retiree benefit plan assets and liabilities for pension, health, and other obligations and net the positions of a company's plans in surplus against those that are in deficit on an after-tax basis. Adjusted debt is not reduced if there are net surpluses.

56. We tax-effect our PRB adjustment amounts (that is, give credit for associated future tax benefits), unless the related tax benefits have already been, or are unlikely to be, realized. We use the tax rates applicable to the company's plans (e.g. reported deferred tax asset) or the current or future expected corporate rate. We do not tax-effect the adjustment amounts if we consider a company's ability to generate taxable profits uncertain.

57. **Adjustments to the income statement** Under IFRS, the period's current service cost--reflecting the present value of future benefits employees earned for services rendered during the period--is the sole item we keep as part of operating expenses. We view the interest expense as a finance charge and reclassify it as such if reported differently. We do not adjust the pension expense under U.S. GAAP because current service costs are already the sole item in reported operating expenses.

58. Under U.S. GAAP, in addition to interest expense, the expected return on plan assets is also separately disclosed and represents the company's subjective, long-range expectation about investment portfolio returns. We use the reported interest expense and expected return on plan assets to arrive at PRB interest. This concept of expected return has been abandoned under IFRS, which calculates a net interest figure by multiplying the deficit (or surplus) on the PRB by the discount rate.

59. Under both U.S. GAAP and IFRS, these measures of PRB interest, if a net expense, are added to reported interest. No adjustment is made if net interest is a net income item.

60. Data requirements:
For adjustments to income statement:

- Service cost;
- Interest cost;
- Expected return on pension plan assets, if applicable;
- Other amounts included in earnings (such as actuarial gains or losses, prior service costs, special benefits, settlements, and curtailments of benefits); and
- Total benefit costs.

For adjustments to balance sheet items:

- Deferred tax assets related to PRB (or the tax rate applicable to related costs);
- Fair value of plan assets; and
- Total plan liabilities.

61. Calculations:
For adjustments to income statement:

- Operating income: Add to EBIT and EBITDA the total amount of PRB costs charged to operating income, less the current service cost for companies that do not report under U.S. GAAP.
- Interest: PRB interest is the net interest cost as reported by companies under IFRS, or interest expense less expected return on plan assets for companies under U.S. GAAP. If PRB interest is a cost, we include it in adjusted interest expense (we do not reduce interest expense if PRB interest is an income item).

For adjustments to balance sheet items:

- Debt: The net balance sheet asset or liability position (or funded status) is calculated as the balance sheet PRB assets minus PRB liabilities. If the funded status is positive, debt is not adjusted. If the funded status is negative, this amount is tax-effected and added to debt.
- In some jurisdictions, the tax benefit is realized before funding the deficit or paying benefits, for example, when the liability is accrued for tax purposes. In such cases, the expected tax benefit only includes tax benefits that have not yet been received.

Asset-retirement obligations

62. Asset retirement obligations (AROs) or decommissioning liabilities are legal obligations associated with a company's retirement of tangible long-term assets. Examples of AROs include the cost of plugging and dismantling oil and gas wells, decommissioning nuclear power plants, treating or storing spent nuclear fuel, and capping and restoring mining and waste disposal sites.

63. We add AROs to debt after deducting any dedicated retirement fund assets or provisions, salvage value, and anticipated tax benefits. We use the tax rates applicable to the ARO (e.g. reported deferred tax asset) or the current corporate rate to calculate the anticipated tax benefits.

64. We generally use the reported ARO figures, but we may make adjustments if we believe any of the company's assumptions are unrealistic. Those assumptions may include the ultimate cost of abandoning an asset, the timing of asset retirement, and the discount rate used to calculate the balance sheet value.

65. In certain situations, companies fund AROs by adding a surcharge to customer prices, or the AROs will be paid by third parties such as a state-related body. In these cases there would typically be

no debt adjustment.

66. The reported accretion of an ARO is akin to noncash interest and similar to PRB interest charges. Accordingly, we reclassify the accretion (net of reported earnings on any dedicated ARO funds) as interest expense.

67. Data requirements:

- The ARO figure (from the financial statements or our estimate).
- Any associated assets set aside for AROs.
- ARO interest costs (and whether charged to operating or financing costs).
- The reported gain or loss on assets set aside for funding AROs.

68. Calculations:

- Debt: Add net ARO to debt (net ARO is the reported or estimated ARO less any assets set aside to fund AROs, multiplied by 1 minus the corporate tax rate or less the reported deferred tax asset).
- EBITDA and FFO: Add ARO interest costs included in operating costs.
- Interest expense: Deduct ARO interest costs (net of ARO fund earnings) from reported operating expenses, if included there, and add to interest expense.

Capitalized development costs

69. We deduct from EBITDA, FFO, and CFO the amount of development costs capitalized during the year. However, where not available, we may use the related annual amortization reported in the financial statements as a proxy for the current year's development costs. We adjust EBIT for the difference between the capitalized development costs and the amortization.

70. In the statement of cash flows, we reclassify capitalized development costs from investing to operating cash flow, reducing operating cash flow and capital expenditures so that free cash flow remains unchanged.

71. **Software development costs:** While U.S. GAAP generally treats development costs as an expense, it has specific exceptions that allow the expenses to be capitalized, which is similar to IFRS. These exceptions include both software developed for internal use and software developed for sale to third parties. For companies that develop software primarily to sell to external parties, we use the technology software and services industry sector-specific adjustment to determine how to treat capitalized software development costs. For companies with a business model that typically does not involve selling software to external third parties, we generally assume that all capitalized software development costs are for internal use, unless we have specific information leading us to believe otherwise. As a result, for these companies, we do not adjust for these costs in EBITDA and FFO. We do this for comparability between those companies that develop software for internal use and those that purchase software and equivalent products and capitalize them.

72. Data requirements:

- Amount of development costs incurred and capitalized during the period, excluding, if practical, capitalized development costs for internal-use software.
- Amortization amount for relevant capitalized costs.

73. Calculations:

- EBITDA, FFO, and CFO: Subtract the amount of capitalized development costs, or, the amortization amount for that period.
- EBIT: Subtract (or add) the difference between the spending and amortization in the period.
- Capital expenditures: Subtract the amount capitalized in the period.

Securitization, sale, and factoring of receivables and other assets

74. We typically adjust debt for securitization, sale and factoring of receivables and other assets (collectively called securitizations), reflecting our view that many assets securitized, sold, or factored (such as trade receivables) are regenerated in the ordinary course of business and need to be financed on an ongoing basis. That is, the assets and trading relationships these assets represent are an integral part of a company's operations. If a company has a recurring need to finance similar assets, we do not presume it will have permanent access to the securitization market, and it may have to meet future funding needs by other means.

75. In certain cases, we may not treat securitizations as a financing. For example, we may not make a debt adjustment when the securitized assets are not regenerated in the ordinary course of business and when we view the securitization as equivalent to an asset sale, for example in the securitization of a tax asset. We view such securitizations as equivalent to an asset sale, for example, if the company retains none of the risk and is not considered likely to support the transaction through moral recourse (this refers to the likelihood that a company will support a securitization even though it's not legally obliged to do so) and there are no contingent or indirect liabilities resulting from the transaction.

76. Under U.S. GAAP and IFRS, companies report cash inflows or outflows related to working capital assets or liabilities, or finance receivables, as operating cash flows. Consequently, securitizations of assets such as receivables affect CFO and the effect may be particularly significant in reporting periods when the securitizations are initiated or mature. When we adjust debt for a securitization, we also adjust CFO to reverse the impact of any cash flows related to the securitization.

77. In some transactions, companies receive a beneficial (or retained) interest in the securitized assets in addition to cash upon the sale of the assets. Any future cash the company receives for beneficial interests is presented as an investment cash flow under U.S. GAAP. Other accounting regimes treat these receipts as an operating cash flow. For consistency, we typically add the cash received for beneficial interests to operating cash flows for U.S. GAAP companies.

78. Data requirements:

- The period-end amount of trade receivables sold or securitized, as well as all other securitized assets that are not reported on the balance sheet and require adjustments according to our criteria.

79. Calculations:

- Assets: Add the amount of period-end trade receivables sold or securitized (that is, the uncollected receivables as of the balance-sheet date) to reported receivables. While the assets securitized are most often receivables, we may also add the securitizations of other assets to total assets.
- Debt: Add the amount of period-end securitized assets to reported debt.
- CFO: Reverse the impact of cash flow movements from the initiation of a securitization,

subsequent changes in amounts securitized, or the securitization's maturity. Rolling over an existing securitization requires no cash flow adjustment. Where beneficial interests are reported as an investing cash flow (U.S. GAAP), we reclassify them as operating cash flows.

Hybrid capital instruments

80. We make adjustments for hybrid capital instruments based on our determination of their equity content:

- Hybrids that have high equity content are excluded from adjusted debt and the interest or dividends are treated as dividends.
- For hybrids with intermediate equity content, 50% of the principal is treated as debt and 50% is excluded from adjusted debt (excluding unpaid accrued interest or dividends, which are added to debt). Similarly, we treat one-half of the period's interest or dividends as dividends and one-half as interest. There is no adjustment to related taxes.
- Hybrids with no equity content are treated as debt and all interest or dividends are treated as interest.

81. The nominal value of hybrid instruments eligible to achieve intermediate or high equity content is typically limited to a percentage of a corporate issuer's capitalization (the application of this is described in our hybrid capital criteria). For example, assuming a 15% limit, if we calculate capitalization to be €1 billion, then hybrid instruments with a nominal value of up to €150 million could be eligible to achieve intermediate equity content, meaning we could deduct €75 million from debt (assuming they were originally reported as debt).

82. We define capitalization as follows:

	Balance sheet adjusted equity (excluding hybrid)
+	Adjusted debt (before hybrid adjustment)
+	Hybrids, as reported
-	Goodwill greater than 10% of total adjusted assets (before goodwill adjustment)
	Capitalization

83. To calculate the percentage described above, the numerator excludes bonds that are mandatorily convertible into shares but includes hybrids to which we assign no equity content. Both amounts are included in the value of capitalization.

84. In all cases, deferred cumulative interest or dividend payments are included in adjusted debt.

85. Data requirements:

- Amount of hybrids, debt, goodwill, and shareholders' equity on the balance sheet.
- Amount of associated interest or dividend expense and interest or dividend payments in the period.
- Amount of accrued unpaid interest or dividends.
- Total adjusted assets (reported total assets plus or minus applicable adjustments).

86. Calculations:

- Hybrids reported as equity: (1) If we classify equity content as high, there is no adjustment to equity. (2) If we classify equity content as intermediate, we deduct 50% of the value from equity and add it to debt. We deduct 50% of the dividend accrued during the accounting period and add it to interest expense. We deduct 50% of the dividend payment in the period from FFO and CFO. (3) If we assign no equity content, we deduct the full principal amount from equity and add it to debt. We add associated dividends to interest expense. We deduct dividends paid from FFO and CFO.

- Hybrids reported as debt: (1) We deduct the value of hybrids with high equity content from debt and add it to equity. We deduct the associated interest charge from interest expense and add it to dividends. We add back the associated interest payment to FFO and CFO. (2) If we classify equity content as intermediate, we deduct 50% of its value from debt and add it to equity. We also deduct 50% of the associated interest charge from interest expense and add it to dividends accrued. We add 50% of the dividend payment in the period to FFO and CFO. (3) If we assign no equity content there is no adjustment because we treat such hybrids as debt.

Capitalized interest

87. In the statement of cash flows, we reclassify any capitalized interest shown as an investing cash flow to operating cash flow. This adjustment reduces CFO and capital expenditures by the amount of interest capitalized in the period. FOCF remains unchanged.

88. Data requirements:

- The amount of capitalized interest during the period.

89. Calculations:

- Interest expense: Add amount of interest capitalized during the period.
- FFO, CFO, and capital expenditures: Subtract the amount of capitalized interest recorded as an investing cash flow.

Financial guarantees

90. We may not add the full guaranteed amount to debt if, should the guarantee be called, the net amount payable would be lower than the guaranteed amount. This could happen, for example, if the company that has provided the guarantee has been counter-guaranteed by another party, that we view as sufficiently creditworthy. In this case, we add the lower amount to debt.

91. Data requirements:

- The value of financial guarantees on and off the balance sheet, net of any tax benefit.

92. Calculations:

- Debt: Add to debt the amount of on- and off-balance-sheet debt equivalent related to financial guarantees, net of any tax benefit.

Earn outs and deferred consideration for business acquisitions

93. We treat as debt contingent and deferred consideration that is payable in cash, and consideration to be settled in shares that does not qualify as equity. The most common example of the latter is a contract to be settled with a variable number of shares. Companies typically record such

arrangements, initially as a liability at fair value and then subsequently mark them to market at the end of each accounting period through charges or credits to income until settled. We add to debt the reported value of the liability-classified contingent consideration on each reporting date, understanding that it is not at amortized cost.

94. Contingent arrangements that require continued employment are technically not part of the consideration paid for the acquisition under U.S. GAAP and IFRS. Rather, these transactions represent remuneration for services after the acquisition. As such, the company does not record the transaction as a liability or expense until the services are performed. We also view such arrangements as payment for services and generally make no analytical adjustments.

95. We exclude the unrealized fair value changes of contingent consideration from EBITDA. In the rare cases where cash settlements are reported in CFO, we remove the outflow because we consider it an investing activity (the acquisition of businesses).

96. Data requirements:

- The carrying value of deferred consideration or liability-classified contingent consideration on the balance sheet date.
- Charges or credits included in reported EBITDA.
- Cash paid for or received from the settlement of contingent consideration reported in cash flows from operating activities.

97. Calculations:

- Debt: Add to debt, if not already reported as such, the carrying amount of deferred consideration at amortized cost, as well as any liability-classified contingent consideration reported at fair value.
- EBITDA: If charges or credits from the change in fair value of contingent consideration are included in reported EBITDA, add them back to or subtract them from EBITDA.
- CFO: In the rare cases where cash settlements are reported in CFO, remove the outflow.

Situational Adjustments

98. Our situational adjustments seek to capture the impact of a company's transactions when we believe they will significantly affect a company's credit metrics. We use analytical judgement to determine if a transaction should result in a situational adjustment.

99. Accounting distortions: In rare circumstances, we may make adjustments to exclude from our financial measures transactions that we view as accounting distortions. An example would be an adjustment to EBITDA to remove the change in a material litigation provision that leads to a very significant gain or loss in the year.

100. Litigation and other contingent liabilities: When we adjust for these liabilities, we add the estimated or actual amount of the exposure (net of any applicable tax deduction) to reported debt.

101. Workers' compensation and self-insurance claims: When we adjust for these liabilities, we add the amount recognized for workers' compensation obligations (net of tax) or the net amount recognized for self-insurance claims (net of tax) to debt.

102. Multi-employer pension plans: Some companies in the U.S. and the Europe, Middle East, and Africa region participate in multi-employer, defined-benefit pension plans on their employees' behalf. If the liability associated with a funding deficit on multi-employer pension plans is very

significant and it is practicable to do so, we may treat the liability as debt, as we do with deficits on single-employer defined-benefit, postretirement obligations. When we make the adjustment, we obtain an estimate of the share of funding deficit or the withdrawal liability for each plan in which a company participates, and we add the estimated amount for all plans, net of tax, to debt.

103. Foreign currency hedges of debt principal: We retranslate foreign currency-denominated debt using the foreign exchange rate locked in by the hedge (or adjust the balance sheet value of debt to equal the hedged principal value). Alternatively, if the prior items are not disclosed, we may add to or subtract from reported debt the fair value of the hedging instrument on the balance-sheet date.

104. Adjustment to debt for the deemed repatriation liability under the 2017 revised U.S. corporate tax code: Under the adjusted debt principle, items that we add to reported debt include incurred liabilities that provide no future offsetting operating benefit. The deemed repatriation liability that the 2017 revised U.S. corporate tax code creates for U.S. corporate issuers is such a liability, in our view. We will therefore typically include this liability, where material, in our adjusted debt. Under the new tax law, companies that are subject to the repatriation liability may pay it in one lump sum or spread it out over eight years. If an issuer chooses to pay the liability over time, we typically add to debt the liability's net present value (NPV). To enhance consistency and comparability with other adjustments we make to debt, we typically use a discount rate of 7% when calculating the NPV.

Sector-Specific Adjustments

105. We use our sector-specific adjustments to reflect the impact of unique industry characteristics on a company's adjusted financial metrics. These sector-specific adjustments are consistent with our four adjustment principles, and are made where applicable and material.

Sector-specific guidance

- Aerospace and defense
- Agribusiness and commodity foods
- Agricultural cooperatives
- Branded nondurables
- Captive finance operations
- Commodity trading
- Financial market infrastructures
- Forest and paper products
- Homebuilders and real estate developers
- Media and entertainment
- Metals and mining upstream
- Oil and gas exploration and production
- Oil refining and marketing
- Oilfield services and equipment

- Operating leasing
- Real estate (REITs)
- Regulated utilities
- Retail and restaurants (auto retailers)
- Technology software and services
- Telecommunications and cable
- Transportation cyclical (airlines, shipping, and trucking)
- Transportation infrastructure

Aerospace and defense

106. **PRB costs recovery under government contracts** Costs for PRBs (both pensions and others such as health insurance) are allowable costs under some U.S. government contracts (including the U.S. Foreign Military Sales program). Therefore, defense contractors, as well as their subcontractors (including firms based outside the U.S.), can generally recover these costs through pricing in their U.S government contracts, with some limitations and calculation/timing differences. We reduce the PRB liability for the ability to recover these costs. We could also apply this adjustment to government contracts in other countries where a similar mechanism exists.

107. Defense contracts come in two general types: fixed price, where the contractor provides a product or service for an agreed price and is responsible for any cost overruns, and cost-plus, where the contractor is reimbursed for all of its allowable costs (sometimes with a limit) plus a fee.

108. We believe defense contractors should be able to recover all of their PRB costs under cost-plus contracts over time. However, we estimate that under fixed-price contracts the contractor would only be able to recover increased costs when a new contract is awarded. Competitive pressures may make it difficult for the contractor to add the full costs to the new contract. Therefore, we estimate only 50% of these costs can be recovered under fixed-price contracts over time.

109. The data needed to make the adjustment are:

- Percentage of revenues derived from U.S. government contracts (A)
- Percentage of contracts that are fixed price (B) and cost plus (C)

110. We reduce our standard adjustments to debt for PRBs by the following percentage:
A x [(B x 50%) + (C)]

Agribusiness and commodity foods

111. **Biological assets:** Under some accounting regimes, agricultural assets may be marked to market on the balance sheet with the fair value gains and losses recognized in the profit and loss statements. In these instances, we typically exclude these non-cash gains and losses from our measures of EBITDA and EBIT, and make adjustments as necessary.

112. **Adjusted readily marketable inventories (ARMI):** For agribusiness and commodity food companies with significant commodity trading activities (defined as representing more than 10% of expected normalized EBIT, EBITDA, or gross margin), we apply the same adjustments for readily marketable inventories as we do for commodities traders to reflect the highly liquid nature of

certain physical commodity trading inventory. (See the Commodities Trading section for more details on ARMI.) As such, for these companies we deduct ARMI from our adjusted debt figures, even for agribusiness companies with significant trading operations that have a weak or vulnerable business risk profile assessment.

Agricultural cooperatives

113. We make the same adjustments for ARMI and biological assets as in the agribusiness and commodity foods section.

114. **Marketing cooperative cost of sales and member payment adjustments:** Marketing cooperatives may account for the cost of the commodity input they are marketing in a variety of ways, depending on the marketed commodity and accounting standards applied. Therefore, to increase comparability, in certain circumstances we adjust the reported cost of goods sold. This includes:

- Cooperatives where the assigned value of sold inventory is deemed to be materially different than market value.
- Cooperatives that do not assign a value to inputs received from patrons.
- Cooperatives that measure their inventory using the net realizable value method.

115. Agricultural marketing cooperatives often operate on what is known as a pooling basis. This is where a marketing cooperative receives its members' agricultural products without obligation to pay a fixed price and commingles those products for processing and marketing purposes. The ability of marketing cooperatives operating on a pooling basis to determine appropriate transfer prices of product deliveries from patrons varies, and this can affect their accounting and financial reporting. Sometimes there is a good basis for recording product transfers between patrons and the cooperative. For example, dairy cooperatives often record product transfers using market order prices. They will assign values to the product received and therefore their inventory and resulting cost of goods sold reflects these assigned values. These assigned values generally represent market value and, therefore, do not require adjustment; however, we may make adjustments (either increases or decreases) to these cooperatives' cost of goods sold where we believe there is a material difference between the assigned values and market value.

116. Other cooperatives have difficulty in determining the market prices of patrons' products when they receive them because of limited cash purchases by other processors and therefore limited market price data. They are usually cooperatives that process and market a high percentage of limited specialty crops. Because amounts that approximate estimated market value are not assigned to products received from patrons, cost of goods sold does not include a charge for the value of the input (i.e., earnings are inflated relative to other cooperatives and companies that recognize a cost related to their input). In these cases, we estimate the input cost of the sold inventory based on market prices or the cost to produce the inventory, and add that estimate to cost of sales (i.e., thereby reducing EBITDA, FFO, and EBIT). In such cases, we would consider any remaining difference between the cooperative's reported member distributions and our cost of sale estimate as a dividend distribution.

117. Lastly, under U.S. GAAP, cooperatives may account for their inventory at net realizable value (as opposed to the lower of cost or market prices, which we prefer). Under this method, a cooperative values its inventory at estimated selling prices less reasonably predictable costs of completion, disposal, and transportation. Changes in the net realizable value of the inventory are recorded in cost of goods sold. We make analytical adjustments to cost of goods sold to reverse these gains or losses as they relate to unsold inventory.

118. Data requirements:

- An estimate of the input cost of the delivered inventory, primarily by either estimating the unit cost from other comparable sales transactions of the commodity and multiplying by the number of units sold, or by estimating the cost to produce the commodity.
- The amount of net realizable value adjustments reported in cost of sales in the period

119. Calculations:
To determine cost of sales:

- For cooperatives where the assigned value of sold inventory is deemed to be materially different than market value, we add to or subtract from cost of sales the difference between market value and the assigned value.
- For cooperatives that do not assign a value to inputs received from patrons, we add the estimated cost of the commodity inventory to cost of sales.
- For cooperatives that measure their inventory using the net realizable value method, we remove from cost of sales the net realizable value gains or losses recorded in the period.

To determine the level of dividends:

- For cooperatives that do not assign a value to inputs received from patrons and report member distribution payments separately as an operating cash outflow (excluding any additional retained member equity and distributions already reported as financing cash inflows/outflows), we subtract from member distributions reported as operating cash outflows the difference between the reported member distributions and our cost of sales estimate, and add that difference to dividends (i.e., and thereby treat that as a financing cash outflow).

Branded nondurables

120. **Excise taxes:** For companies operating in sectors where excise taxes are levied against consumers and collected by the company, including tobacco and alcoholic beverages, we deduct such excise taxes from both revenues and the cost of sales if the company includes them in their reported revenues figure, as we do not consider those tax items as operating revenues or costs.

Captive finance operations

121. Data requirements:

- Reported captive finance unit assets. We determine captive finance assets as the sum of on- and off-balance-sheet (e.g. securitizations) lease receivables, leased assets (when the captive finance unit acts as operating lessor), loans given to customers, and any other earning assets.
- Reported captive finance unit debt. We use debt as defined in our "Ratios And Adjustments" criteria. For example, we adjust reported debt to reflect the debt equivalent of securitized assets and hybrid securities. Intercompany debt on the captive's books is generally included in our definition of captive debt as long as the parent has originated the intercompany debt from third parties. In cases where the parent has no reported debt and it lends to its captive, we would exclude the intercompany loan from the captive's debt. We cap the captive's debt at the adjusted consolidated debt level. Similar adjustment may be warranted for intercompany debt if the captive lends to the parent.
- Reported captive finance unit equity. We use the captive finance company's equity including

any minority interest if the captive is not fully owned.

- Reported captive finance unit revenue.
- Reported captive finance unit EBIT or EBITDA.
- Reported captive finance unit operating expenses.
- Reported captive finance unit depreciation and amortization (D&A) and non-current asset impairments.
- Reported captive finance unit interest expense.
- Reported captive finance unit current tax expense.
- Reported captive finance unit interest paid.
- Reported captive finance unit cash tax paid.
- Reported captive finance unit interest income.
- Reported captive finance unit cash flows from operation.
- Reported captive finance unit capital expenditure.
- Reported captive finance unit cash, cash equivalents, and liquid investments.

122. Calculations:

- Captive finance unit debt: We use the reported captive finance unit debt as defined above. If the reported figure is not available, we estimate the captive's debt and equity based on the captive's assets and an appropriate debt-to-equity ratio. We determine the appropriate debt-to-equity ratio using table 6 of "The Impact of Captive Finance Operations on Nonfinancial Corporate Issuers" criteria. First, we select the leverage range for an intermediate/significant asset and leverage risk corresponding to the captive's final portfolio quality assessment. Then, we generally select the mid-point of that leverage range as the debt-to-equity ratio unless we believe that the high or low end of the range is more appropriate, based on the relative strength or weakness of the portfolio quality within the assessment category. This may be informed by the severity of historical losses, and positive or negative underwriting standards considerations. Last, we cap the captive finance unit's estimated debt resulting from the above calculation at the adjusted consolidated debt level of the combined enterprise.
- Captive finance equity. If the reported figure is not available, we calculate the captive finance unit's equity by deducting the captive finance unit debt, as determined above, from total captive finance unit assets.
- Captive finance unit revenues: If the reported figure is not available, we estimate the captive finance unit revenues by multiplying the average captive finance unit asset value (mathematical average of opening and closing assets as disclosed above) by an appropriate revenue factor. We use 15% as the revenue factor, unless we have reasons to believe, based on our discussions with the company, that a different revenue factor would be more appropriate.
- Captive finance unit EBITDA: We calculate captive finance unit EBITDA as captive finance revenue less captive finance operating expenses, plus captive finance D&A and non-current asset impairment. If reported figures are not available, we calculate the individual elements as discussed below. We do not take into account any dividend flow between the captive finance unit and its parent company in calculating the parent's adjusted financial metrics.
- Captive finance unit operating expenses: We estimate these by multiplying the average captive finance unit asset value (mathematical average of the opening and closing asset as determined

above) by an appropriate operating expense factor. The captive finance unit's D&A and impairment may be material when the captive finance unit acts as operating lessor and therefore holds material nonfinancial assets on its balance sheet. In those cases, we estimate D&A by multiplying the average captive finance unit nonfinancial asset value (mathematical average of opening and closing asset) by an appropriate depreciation and amortization rate that represents the average useful lives of the leased assets. We do not estimate impairment charges.

- Captive finance unit interest expense: If the reported figure is not available, we calculate the captive finance unit's interest expense by applying an appropriate interest rate on the mathematical average of the previous and current year-end captive finance unit's debt. We use a long-term (such as a 10-year) government bond interest rate, unless we have reasons to believe, based on our discussions with the company, that a different interest rate is more appropriate.
- Captive interest paid: If the reported figure is not available, we would take the captive finance unit's interest expense as determined above.
- Captive finance unit cash tax paid: If the reported figure is not available, we calculate the captive finance unit's cash tax paid by applying an appropriate tax rate to the theoretical captive finance unit profit before taxes. The tax rate reflects the rate applicable for the captive finance unit. This tax rate may not be the same as the parent's tax rate if the captive finance unit is in a different tax jurisdiction.
- Captive finance net loss ratio: We calculate the net loss ratio as gross losses minus recoveries divided by average net earning assets outstanding. For operating lease assets, we include in the net loss ratio both credit losses on outstanding receivables and losses on residual value whenever possible. We include all managed assets in our analysis, adding back the off-balance-sheet assets to determine net earning assets.
- Accessible cash. When sufficient evidence is available that the captive's cash, cash equivalents, and liquid investments are accessible to the parent and available for debt repayment, we include them in our calculation of accessible cash.

Commodities trading

123. In deriving and interpreting a commodities trader's financial measures, it is critical to consider the accounting valuation method for trading assets and liabilities (including both physical positions and derivatives) and the approach to recognizing gains and losses in the income statement. In our experience, virtually all commodities traders report under IFRS or U.S. GAAP and therefore mark-to-market a dominant share of trading-related assets and liabilities, and traders recognize the related gains and losses--realized and unrealized--in earnings on an ongoing basis. We determine a commodities trader's EBIT, EBITDA, and gross margin by including both realized and unrealized trading gains and losses. For a commodities trader, unrealized gains and losses, although non-cash, are an important component of core earnings, and including them in profitability measures provides a more accurate gauge of ongoing financial performance because derivative gains or losses on the physical position tend to be offset by losses or gains on the corresponding derivative transaction.

124. When adjusting a commodities trading company's credit measures for leases and related service contracts, we include commitments related to vessel chartering, storage facilities, and other fixed assets.

125. We do not net accessible cash for commodities traders with weak business positions or less

supportive trading risk management and trading risk positions.

126. **ARMI:** To reflect the highly liquid nature of certain physical commodities trading inventory, we make an additional adjustment for commodities traders in that we deduct ARMI to determine debt and related financial measures (except when calculating the debt-to-debt-plus-equity supplementary ratio). Such netting is made against total debt, not just short-term debt, for all commodities traders (including those with a weak business position or less supportive trading risk management and trading risk position). See the description of core and supplementary ratios in our "Commodities Trading Industry Methodology."

127. We include in ARMI the portion of inventory that meets all of the following conditions:

- The inventory is either hedged or "pre-sold";
- The inventory could realistically be liquidated within 30 days (whatever the ultimate terms of the trading position), and the related hedges could be unwound (we net from the value of the gross trading asset any cash needed to terminate the related hedges);
- The inventory liquidation would not harm the business franchise of the commodities trader--for example, where the company serves as the "market-maker" for the commodity in question;
- The inventory is not held for processing by the company; rather, we include only inventory that we believe will be used only for trading purposes; and
- The proceeds of any inventory liquidation would be accessible for debt repayment, i.e., not trapped in a foreign subsidiary, unless local debt could be serviced.

128. In addition, to account for losses that could result from a rapid liquidation, we apply a haircut to reported inventory values according to our view of the relevant commodity market's volatility. We base the haircut on the commodity risk assessments in table 3 of our commodities trading industry methodology. For category 1 commodities the haircut is 10%, and for category 2 the haircut is 25%.

129. To apply this adjustment, we use a broad breakdown of trading inventory by commodity, generalized information about how much the commodity is hedged or pre-sold, and the duration of related trades.

Financial market infrastructures

130. **Treatment of CPP and CSD balances:** Within the financial market infrastructures (FMI) sector, international central securities depositories (ICSDs) typically have large varying amounts of deposits that appear on their balance sheets but are dedicated to client settlement activity and are invested in highly liquid, highly creditworthy instruments rather than being available to support the corporate activity of the ICSD. Similarly, clearinghouse balance sheets substantially consist of client-related assets and liabilities, such as initial margins and the replacement value of some types of unsettled trades.

131. For ICSDs, clearinghouses, and groups that have clearinghouses or ICSDs, we typically do not include clearing or settlement assets or obligations, nor client deposits and related investments (for ICSDs) in our balance sheet measures (for example, in adjusted debt and adjusted assets). "Clearing obligations" typically refer to clearing liabilities that are usually non-debt and may include initial or variation margin postings. "Settlement obligations" typically refer to member deposits lodged at ICSDs. Similarly, we tend to exclude the movement in these assets and liabilities from our cash flow analysis.

132. **Accessible cash and liquid investments:** Our approach to accessible cash and liquid investments reflects that FMIs tend to be more highly regulated than other corporate sectors, with subsidiaries often subject to regulatory prudential requirements. For example, we treat as trapped cash in regulated subsidiaries that supports minimum capital or other loss absorbency requirements. Where we see cash balances as volatile, we make a prudent assumption of the level of accessible cash that can be relied on. For example, where cash balances are seasonal, we adjust accessible cash if we see period-end reported balances as unrepresentative. Volatility may also arise, for example, if an FMI is exposed to potential losses on unsecured exposures.

Forest and paper products

133. **Valuation of timberlands:** Under certain accounting frameworks (such as IFRS) timberlands are carried at fair value and therefore equity reflects the appreciated value of these assets. However, under other accounting regimes (such as U.S. GAAP) timberlands are carried at historical cost. The market value of timberland is often substantially greater than book value, and we believe that book value-based ratios could materially overstate a timberland company's leverage. To gain comparability between companies that mark their timberlands to market compared with those that carry them at cost, we make adjustments to the equity of those that carry them at cost to evaluate leverage and return on capital.

134. We do not, however, make a corresponding mark-to-market adjustment to EBIT for return on capital. Likewise, any mark-to-market adjustments recorded in the reported results of IFRS reporters are excluded from our measure of EBIT.

135. We estimate the market value of timberlands on a company-specific basis because values vary by region and incorporate third-party appraisals and recent timberland transactions into our estimates when available.

136. Calculations:

- Equity: We add to equity the difference between the estimated market value of timberlands and the corresponding book value.

Homebuilders and real estate developers

137. **Land procurement approaches:** We don't adjust debt to reflect land options and purchase commitments even when we view them as inflexible or highly likely to be exercised and honored. This is because, in our financial forecasts--which partly serve as the basis of our assessment of cash flow/leverage and liquidity--we factor in our expectations regarding the cost of land purchases and the related expected financing mix.

138. **Impairment charges:** Inventory (consisting of houses or buildings under construction, completed houses or buildings that have not been sold, land under development, and land held for future development) is virtually always the largest single asset on a homebuilder's or developer's balance sheet and is usually valued at the lower of cost or market price. In industry downturns, valuing the inventory at market price can lead to large inventory write-down charges in the income statement. Given the unevenness of these charges, we generally add back these charges to our profitability and cash flow proxy measures.

139. Data requirements:

- Write-down charges related to inventory in the period considered to be nonrecurring.

140. Calculations:

- EBITDA, EBIT, and FFO: Add the inventory write-down charges that are considered to be nonrecurring.

141. **Revaluation gains and losses:** Where companies mark their properties to market on an ongoing basis (as under IFRS), we generally exclude the resulting unrealized revaluation gains and losses from our profitability and cash flow proxy measures. We believe that these unrealized gains and losses, while stemming from operating activities, can distort the company's financial performance metrics. Nonetheless, we do account for the market factors that cause revaluation gains and losses, for example, in determining our forecast assumptions because these can be important indicators of market trends.

142. Data requirements:

- Revaluation gains and losses related to inventory in the period.

143. Calculations:

- EBITDA, EBIT, and FFO: Subtract or add revaluations gains and losses.

144. **Capitalized interest:** Homebuilders and developers may capitalize a significant amount of their cash interest costs to inventory (including property construction in progress) because land acquisition and construction costs are typically capitalized until buildings are built on the lots. The recognition of interest costs in the income statement is therefore deferred until the related inventory is sold. For analytical purposes, similar to our treatment of interest capitalized as part of property, plant, and equipment, we seek to recognize interest costs as an expense in the period when incurred rather than when the inventory is sold and make adjustments to reverse the accounting. In terms of analyzing cash flows, we include all cash paid for interest as an operating cash flow.

145. Data requirements:

- The amount of interest costs capitalized as part of inventory in the period.
- The amount of interest costs previously capitalized as part of inventory that was recognized as part of cost of goods sold in the period.
- Cash paid for interest costs that is capitalized as part of inventory reported as either investing activities or financing activities.

146. Calculations:

- Interest cost capitalized is subtracted from the cost of goods sold.
- EBITDA and EBIT: Add to EBITDA and EBIT the amount of interest that was previously capitalized that was released to cost of goods sold in the period.
- Interest expense: Add to interest expense the amount of interest capitalized in the period.
- CFO: Subtract from CFO any interest reported as either investing or financing.

147. **Unconsolidated affiliates:** It is common for developers and sometimes homebuilders to conduct a large portion of their business through partly owned subsidiaries or joint ventures, thereby sharing risks and investments with other owners. These entities are often organized around individual properties or groups of properties and have their own external debt financing. Under current IFRS and U.S. accounting standards, these affiliates are generally accounted for using the equity method if the company's ownership interest is less than 50%. We may reflect contribution from unconsolidated affiliates by adding dividend payments received from those affiliates to EBITDA.

148. Generally, we utilize pro rata consolidation where we view the leverage of equity method affiliates as material. In some cases, equity method accounting can understate the true extent of financial leverage being employed within the broader group from an analytical perspective. In such cases, pro rata consolidation more meaningfully depicts the economic reality, and so often we adjust the financial statements to reflect pro rata debt, earnings, and interest expense, if available. Alternatively, if a company is unlikely to support the debt of an ailing affiliate, the analysis might not include the debt in question in the leverage ratios. At the other extreme, if a company is highly likely to support all the affiliates' obligations our analysis might fully consolidate the affiliate for analytical purposes.

Media and entertainment

149. **Program development and acquisition costs:** Across multiple media subsectors, program development and acquisition costs (e.g., film producers' programming and film expenditures, educational publishers' program development costs, and local TV broadcasters' program rights) are capitalized and amortized to income using various systematic approaches. However, we view these items as operating and we treat this amortization as a cost of sales (i.e., an operating cost) and therefore include the amortization (and any related write-downs) in EBITDA and FFO.

150. Consistent with this characterization, we also view the cash paid for these assets to be operating. However, companies classify the cash outflow in the statement of cash flows in a variety of ways. We reclassify any cash outflows related to these capitalized costs reported as investing cash flows and do not include them in our definition of capital expenditures.

151. Data requirements:

- Amount of programming development and acquisition costs incurred and capitalized during the period that are classified as investing cash flows.
- Amount of related amortization expense.

152. Calculations:

- Subtract from EBITDA and FFO the relevant amortization expense for the period if it is not already reported as an operating expense.
- Subtract from CFO any capitalized program development and acquisition costs classified as an investing cash outflow.
- Subtract from capital expenditures any capitalized program development and acquisition costs reported as capital expenditures.

Metals and mining upstream industry

153. **Streaming transactions:** A streaming transaction is a feature of the mining industry and is an agreement whereby a commodity producer--for example, a base metals miner that also yields some precious metals byproduct through its mining--sells the right to a share of its future byproduct production at a preset price in exchange for an upfront payment, which becomes a liability of the commodity producer. The upfront payment is recognized as a trade liability because it is related to a future sale, and it often ranks pari passu with other unsecured debt of the operating mine (in some cases, the liability may also benefit from guarantees). The use of funds is sometimes restricted to funding the construction or expansion of the mine from which the byproduct will be delivered, and in some instances the agreement may be subject to completion tests.

154. Such agreements are typically long-dated--in some cases, covering the life of production--and the buyer has the rights to a portion of the output until the agreement terminates. The transaction provides the commodity producer with upfront financing and repayment flexibility because there are no fixed-volume delivery obligations. The streaming agreement also typically allows the commodity producer to retain ownership and control of the producing unit, and secured interests are limited to the agreed-upon share of byproduct reserves and production.

155. We view these transactions as a form of financing, and, therefore, we adjust our debt and related credit measures if the transactions have some combination of the following features:

- If they are done in lieu of borrowing;
- If they are repayable in cash if they are not satisfied by the product's delivery;
- If the counterparty has recourse to the issuer or a guarantor in the case of insolvency;
- If repayment can be accelerated upon an event of default; or
- If there is high overcollateralization or security to production coverage or some other mechanism that provides greater certainty of repayment.

156. We nevertheless recognize the lower default risk of streaming transactions, given the absence of fixed-volume delivery obligations, as well as significant financial flexibility the transactions can provide to low-rated or start-up mining companies.

157. For financial reporting purposes, issuers generally determine the amortization of the obligation that is recognized as revenue for each period using a units-of-production method. At inception, the company determines a per-unit amortization amount based on the upfront prepayment amount divided by the total units it expects to deliver to the counterparty over the life of the contract. The price per unit delivered varies over time based on changes in the ultimate expected output. As such, revenue, EBITDA, and FFO will include the non-cash amortization, whereas CFO will not.

158. These contracts usually do not contain a stated interest rate, and we have found that accounting practices differ among companies, whereby some impute interest on these transactions in their financial statements, and others do not. Imputation of interest affects the amount of revenue and interest expense recognized. If an issuer is imputing interest on these transactions at a reasonable rate, we do not adjust the reported revenue, related EBITDA, and interest expense. We instead add the reported unamortized obligation to adjusted debt. For an issuer that does not impute interest, we maintain an amortization schedule and make additional adjustments as detailed below.

159. Data requirements:

- The original upfront payment amount.

- The interest rate provided by the issuer or computed based on the expected timing, volume, and price of delivery. Alternatively, we may use an estimate of this rate based on the issuer's average cost of debt.
- The amount of amortization during the period.
- An estimate of the incremental amortization rate, if interest had been imputed based on the percent difference between the total undiscounted value of the product expected to be delivered and the amount of the upfront payment received.

160. Calculations:

- Debt: We add the unamortized obligation as adjusted for imputed interest if needed.
- EBITDA: We add the incremental revenue that would have been recognized if interest had been imputed at the implicit rate, calculated as the amortization during the period times the incremental amortization rate.
- Interest expense: We add the interest imputed on the adjusted obligation on a compound basis.
- CFO: In the period when the upfront payment is received, we subtract the upfront payment from cash flow from operations. No adjustments are made in subsequent periods.

Oil and gas exploration and production (E&P)

161. **Exploration costs:** Oil and gas E&P companies must choose between two accounting methods: full cost or successful efforts, which differ in terms of what investment outlays companies capitalize or expense. A full-cost company capitalizes all costs of property acquisition, exploration, and development. A company using the successful-efforts accounting approach only capitalizes property acquisition costs, drilling, and development costs from successful exploration. Companies using the successful-efforts method report their exploration expenses separately in the income statement while full-cost companies capitalize exploration costs and do not report exploration expense separately in the income statement.

162. To gain comparability within the sector, we adjust EBITDA to exclude all exploration costs. This adjusted measure conforms to the industry standard known as EBITDAX. With this adjustment, we calculate all EBITDA-related ratios using our equivalent of EBITDAX. Although we add back the exploration expense companies report using successful-efforts accounting to derive EBITDA, we reverse this adjustment when calculating FFO; in other words, we reduce FFO by the amount of exploration costs. We take this alternative approach to have some degree of comparability with other industries. Likewise, companies often report cash paid for exploration in the statement of cash flows differently. We generally do not attempt to make adjustments to these amounts in the statement of cash flows, but rather rely more heavily on FOCF to debt as a supplemental measure of cash flow to leverage because the classification of these amounts doesn't affect this.

163. Data requirements:

- Exploration expense in the period as reported by companies following the successful-efforts approach.

164. Calculations:

- EBITDA: We add back to the reported EBITDA the exploration expense of companies that follow the successful-efforts approach.

- FFO: We include the exploration cost in the calculation of FFO.

165. **Economic hedging:** E&P companies often manage their exposure to fluctuations in commodity prices and foreign currencies through hedges. When derivatives are not designated as hedges as provided for under accounting standards or do not qualify for hedge accounting, derivative gains and losses flow through the income statement each period. Realized gains and losses relate to transactions in the current period, and unrealized gains and losses to future transactions. When the derivatives do not qualify for hedge accounting or are not designated as hedges, we typically eliminate from EBITDA unrealized gains and losses relating to future production, where we can identify these effects, focusing on earnings that only include realized hedge effects.

166. **Volumetric production payments:** A volumetric production payment (VPP) is an arrangement in which an E&P company agrees to deliver a specified quantity of hydrocarbons from specific properties (or fields) to a counterparty in return for a fixed amount of cash received at the beginning of the transaction. The seller often bears all of the production and development costs associated with delivering the agreed-upon volumes. The buyer receives a non-operating interest in the oil and gas properties that produce the required volumes. The security is a real interest in the producing properties that the parties expect to survive any bankruptcy of the E&P company that sold the VPP. After the total requisite volumes are delivered, the production payment arrangement terminates and the conveyed interest reverts back to the seller.

167. We view VPPs structured with a high level of investor protection (in terms of production coverage) as debt-like obligations rather than asset sales given the risks the E&P companies retain. In typical deals, there is substantial overcollateralization, with total field reserves significantly exceeding the volumes the seller promises under the VPP contract. The seller must deliver the agreed-upon volumes and incurs all associated operating and capital costs. If the seller does not meet the obligation, it would risk losing all its reserves in the field.

168. We would view a VPP structured with minimal overcollateralization to be closer to an asset sale because the transfer of risk would be more substantial. However, even in this case the VPP has some debt-like qualities because the company must pay the operating expenses associated with the VPP until delivery of the final volumes.

169. To make the adjustment to debt, we use a fair market value approach and the New York Mercantile Exchange (NYMEX) futures curve to calculate the expected value of the barrels to be delivered, which we consider to be debt. If hydrocarbon prices increase, so would the debt adjustment.

170. Data requirements:

- Schedule of oil and natural gas volumes yet to be delivered under the VPP;
- Oil and natural gas volumes produced during the year from the VPPs;
- NYMEX futures curve for oil and natural gas prices as of period end; and
- Pricing differentials (for quality differences and geographic location) for the VPP volumes relative to NYMEX.

171. Calculations:

- Debt: We multiply the oil and natural gas volumes to be delivered in each year of the contract by the futures price (adjusted for quality and location differentials) in that year. We then calculate the value of this revenue stream using a discount rate commensurate with the company's secured borrowing rate.

- Interest expense: We impute interest expense on the adjustment to debt using the company's secured borrowing rate. We apply the rate to the average of the calculated VPP obligation at current and previous period-end.
- Debt-to-reserves: We add the hydrocarbon volumes the seller hasn't yet delivered under the VPP back to reported reserves.
- Selling and lifting costs: We add the oil and gas volumes produced to meet the VPP requirements in calculating per-unit selling prices and lifting costs.
- CFO and FFO: We subtract the VPP cash proceeds from CFO and FFO.

Oil refining and marketing industry

172. Liquidation gains: When a company using the last in, first out (LIFO) method has inventory balances that decrease over a period of time, LIFO liquidation may result. This means that older layers of inventory are turned into cost of goods sold as a result ("older" refers to inventory in terms of accounting and not necessarily in a physical sense). Assuming an inflationary environment, the cost of goods sold is reduced and, as a result, income increases because of LIFO liquidation gains. To capture the true sustainable profitability of a company, we generally exclude the gains generated from LIFO liquidation from our profitability measures.

173. Data requirements:

- LIFO liquidation gains from the income statement.

174. Calculations:

- EBITDA, EBIT and FFO: Deduct LIFO liquidation gains from EBITDA, EBIT and FFO.

Oilfield services and equipment industry

175. **Seismic accounting:** When seismic companies capture seismic data that they expect to sell to multiple clients, they capitalize the associated costs and amortize these costs over the expected useful lives of the data. However, we adjust these companies' financial results effectively recognizing these expenditures as an operating expense as incurred.

176. Data requirements:

- Capital expenditures for multiclient data acquisition for the period.
- Amortization of multiclient data acquisition costs for the period.

177. Calculations:

- EBITDA, FFO, and CFO: Deduct capital expenditures for multiclient data acquisition from EBITDA, FFO, and CFO.
- Capital spending: Deduct capital expenditures for multiclient data acquisition from total capital spending.
- EBIT: Deduct/add the difference between capital expenditures and amortization expense for multiclient data acquisition costs.

Operating leasing

178. Operating lease companies may provide finance leases as well as operating leases to their customers. Payments customers make under the finance leases are accounted for as interest income (part of revenues) or repayment of principal (recorded as a financing cash flow). Since all of the payments, both interest and principal, are sources of cash flow to service debt, we add the repayment of principal to FFO, reclassifying those payments as an operating cash flow.

179. Operating lease companies often sell equipment as part of a normal pattern of acquiring, leasing out, and disposing of their assets. If gains and losses realized on such equipment sales are part of the normal turnover of leased assets, we include such gains and losses as an adjustment to depreciation and an operating expense.

Real estate (REITs)

180. **Straight-line rent:** The accounting treatment of rent payments received under real estate leases averages them out over the life of the lease. Consequently, reported rent revenue may differ from actual cash rent received where the minimum rent payment varies over the life of the lease. This can happen when there are periodic contractual rent increases or when the lease provides for an initial period with no rent or with discounted rent, following which normal periodic cash rent payments are required. Depending on the lease terms and life cycle, cash rent received may be higher or lower than reported rental income. For real estate companies, we will reverse, when material, the straight-line rent smoothing in calculating EBITDA. This is consistent with industry standards and with our focus in this sector on the amount of cash rent actually received by the company during the period. We adjust revenues, EBIT, EBITDA, and FFO, by the amount that straight-line rental revenue reported exceeds or falls below cash rents received for the respective period.

181. **Unconsolidated affiliates:** It is common for real estate companies to conduct a large portion of their business through partly owned subsidiaries or joint ventures, thereby sharing risks with other owners. These entities are often organized around individual properties or groups of properties and have their own external debt financing. Under accounting standards, these affiliates are generally accounted for using the equity method if the company's ownership interest is 50% or less. From an analytical perspective, equity method accounting can understate the true extent of financial leverage within the broader group. As a result:

- We may adjust the financial statements to exclude dividends received and reflect pro rata consolidation of debt, earnings, and interest expense if, in our view, this better depicts the economic reality.
- If we believe the company is highly likely to support all the affiliates' obligations, we may apply full consolidation.
- Alternatively, if we believe a company is unlikely to support the debt of an ailing affiliate, we might exclude that affiliate from our financial measures, even if it is fully consolidated for financial reporting purposes. Even though these debt obligations are typically nonrecourse property-level debt, we will only exclude the ailing affiliate's debt from our financial measures if we believe the failure to support the affiliate will not limit the issuer's access to capital markets. Additionally, in order for us to exclude the debt of these affiliates, the debt should not have cross-default, cross-acceleration, or any similar influence on the debt issued by the real estate company. Examples of companies where we would do this include minority-owned joint

ventures and properties included in commercial mortgage-backed securitizations.

Capitalized interest:

182. Real estate companies engaged in sizable debt-financed development projects may capitalize a significant amount of their cash interest costs, thereby deferring the recognition of interest expense on the income statement. In our analysis, we factor in capitalized interest as an expense in the period when incurred. The valuation of property, plant, and equipment includes, under U.S. GAAP, a cost-of-carry element relating to multiperiod project expenditures. Part of the rationale is that the company must factor in the carrying costs when deciding on a project's economics, but this obscures the amount that actually must be paid during the period. Companies may also have significant discretion with respect to the amounts they capitalize, making comparisons difficult.

Regulated utilities

183. **Inflation linked debt:** Some companies in the regulated electricity and water sectors issue significant amounts of inflation-linked debt, notably in the U.K. where future regulated rate increases are linked to inflation indexes such as the retail price index (RPI). Inflation-linked debt is also commonly issued across several sectors in Israel. Inflation-linked debt usually has a long tenor (20-30 years), and a low annual cash coupon (e.g., 1%-3%) that, without indexation, would usually represent a below-market cost of debt at issuance for the issuer, as it only reflects real term interest rates.

184. A distinct, typical feature of inflation-linked debt is the deferral of indexation payments to maturity. We view the accrual of principal indexation as a partial non-cash coupon. Deferral of its payment does not mean that this debt is any cheaper; simply, a portion of its periodic cost, which may be substantial, is being deferred to maturity.

185. We typically apply a charge for the indexation of principal for inflation-linked debt in our calculation of FFO. We believe this approach better captures the after-interest cash flow the company's operations generate, including the full cost of the debt used to finance those operations. Where companies have not disclosed the amount of principal indexation, we may estimate the adjustment.

186. No adjustment is typically required to be made to reported debt if this includes the effect of the indexation component (the "deferred interest" portion) on a cumulative, compounded basis.

187. Where possible we make similar adjustments where companies use derivatives to synthetically convert debt into inflation-linked debt. This can require deducting from FFO the inflation payable of an inflation-linked swap and adding to debt the portion of the derivative's fair value that corresponds to the cumulative deferred interest.

188. **Purchased power adjustment:** We may view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. If the lease liabilities include PPAs, we may reduce the lease liabilities to reflect the burden of the contractual payments that ultimately rests with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity, or where the regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs. Conversely, if the lease liabilities exclude PPAs because of the contracts' terms, and we believe those contracts are very material, we may add to debt an appropriate percentage (using an analytically determined risk factor) of the present value (using a company-specific discount rate)

of the stream of capacity payments associated with the PPAs.

189. **Natural gas inventory adjustment:** In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-term debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

190. Data requirements:

- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers.

191. Calculations:

- Adjustment to debt: we subtract the identified short-term debt from total debt.

192. **Securitized debt adjustment:** For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property.
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run.
- Reserve accounts to cover any temporary short-term shortfall in collections.

193. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures.

194. Data requirements:

- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

195. Calculations:

- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after D&A and EBIT: we reduce D&A related to the securitized

debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.

- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.
- Operating cash flows: We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Retail and restaurants (auto retailers)

196. **Auto retailers floor plan financing:** Despite the differing accounting characterizations of auto retailers' floor plan financing arrangements (those with automakers' captive finance arms and those with third-party financiers), we consider auto retailers' floor plan borrowings, regardless of source, more akin to trade payables than to debt. This is due to the borrowings' high loan-to-value ratios (typically 100%), widespread availability, and long-dated maturity, with repayment generally occurring once vehicles are sold, and because of a long history of manufacturer subsidies largely offsets borrowing costs.

197. We view floor plan borrowings as a part of working capital. When floor plan borrowings are included within reported debt, we move those liabilities to accounts payable. Likewise, we consider floor plan interest expense as an operating cost rather than a financing cost and add it to the cost of sales. We do not make any change in the treatment of floor plan interest assistance, which is generally already included in cost of sales. On the statement of cash flows, we include changes in all floor plan borrowings (both with captive and third parties) in the working capital section of cash flow from operations.

198. Data requirements:

- Amount of floor plan borrowings reported as debt.
- Amount of floor plan interest expense reported by the company in interest expense for the period; and
- Floor plan borrowings/repayment reported by the company under financing activity in its statement of cash flows for the period.

199. Calculations:

- Debt: We subtract any floor plan borrowings reported as debt in the financial statements.
- EBITDA and FFO: We subtract floor plan interest expense from total interest expense and cash interest paid (if included in reported cash interest) and treat it as a part of operating expense, thus reducing EBITDA by the floor plan interest.
- CFO: We reverse the impact of floor plan borrowings and repayments in the financing activity cash flow and treat it as a part of working capital (i.e., change in accounts payable), thus impacting cash flow from operations.

Technology software and services

200. **Acquired deferred revenue:** Companies in this sector often have significant deferred revenue balances, given the pattern of cash received relative to when they provide services and what revenue recognition methods they employ. At any given time, the deferred revenue amount recorded on a company's balance sheet generally represents the cash received in advance, less the amount amortized to revenue for goods and services provided to date. This balance sheet amount differs from the fair value of this performance obligation, which must be recorded at the date of an acquisition. Because of how acquired deferred revenue is valued at the time of acquisition and its subsequent impact on revenue, it can distort the acquiring company's financial results, making them less representative of ongoing operations. We therefore make an adjustment to EBITDA and FFO to mitigate this distortion by adding to EBITDA and FFO the amortization in the period of the fair value adjustment to acquired deferred revenue.

201. **Software development costs:** For companies that operate with a business model that includes selling software to external parties, we aim to adjust for the capitalization of development costs for external use software if the information is available and the amounts material. Without clear reporting that delineates the software development costs into internal versus external use, we use analytical judgement to determine the appropriate amount of our adjustment.

202. We do not reverse the capitalization of software for internal use, consistent with our treatment of internal use software costs across all sectors. We do reverse the capitalization of software for external use and include it as an expense. In the income statement, this means reversing the amortization of previously capitalized costs and increasing research and development costs by the amount capitalized during the period. The net effect on adjusted EBITDA is a decrease by the amount capitalized during the period. The net effect on EBIT is a decrease (or increase) by the amount capitalized during the period minus the amount amortized during the period.

Telecommunications and cable

203. **Subscriber acquisition costs:** Wireless telecom companies incur various costs to acquire new customers or subscribers, such as sales commissions and subsidies for wireless handsets, known as subscriber acquisition costs (SAC; also known as customer acquisition costs). While some wireless telecom companies expense SAC, others capitalize these costs, which makes comparing their reported financial performance difficult.

204. To enhance comparability, we adjust reported financial statements when a company capitalizes SAC and the relevant information is disclosed and the amounts are material. The adjustment aims to treat the capitalized SAC as if they had been expensed in the period incurred. The adjustment reduces EBITDA, FFO, CFO, and capital expenditures (if reported) by the amount of SAC capitalized during the year. Similarly, we will reduce the D&A expense for SAC amortization. Without sufficient disclosures, we would reduce the D&A by the amount capitalized so that the EBIT measures are not unduly suppressed.

205. Data requirements:

- Amount of SAC incurred and capitalized during the period; and
- Amortization amount for SAC costs during the period.

206. Calculations:

- EBITDA, FFO, CFO, and capital expenditures: Subtract the amount of capitalized SAC;
- EBIT: Subtract (or add) the difference between the amount of SAC capitalized and the SAC

amortization during the period; and

- D&A: Subtract the amount of SAC amortized during the period.

207. **Adjustment to debt and EBITDA for master service agreements:** The International Accounting Standards Board's IFRS 16 will become effective for companies reporting under IFRS in 2019. The new rule will treat telecom tower master service agreements as an expense. We adjust for these contracts the same way that we adjust for operating leases to enhance comparability between mobile network operators that:

- Own towers;
- Lease towers through a master lease agreement; or
- Have signed a service agreement.

208. In our view, the current differences between the three models are not material enough to require different analytical treatment. The towers serve a similar purpose for network operators in all three cases, and are crucial to ongoing operations. Given that mobile operators need to either own these assets or ensure they have long-term access to them, we see a service agreement as similar to an operating lease.

209. Adjusting the mobile operator's figures to account for its service agreement has two material implications:

- Higher profitability because we exclude the fees paid to the tower company from operating expenses; as a result, EBITDA margins are higher.
- Higher adjusted debt amount because we are adding the liability to the balance sheet. The impact on a mobile operator's credit metrics will generally depend on the length of the contract and the magnitude of the operator's debt.

210. Table 1 shows an example of how we would adjust the figures for an operator that makes annual payments of €40 under a 15-year contract with a tower company. Capitalizing the annual payment not only raises EBITDA but also debt, because we value the future obligation at a 7% discount. The net effect in this example is a leverage increase of 0.66x.

Table 1

Example Of Adjustments Made For A Master Service Agreement

	Revenues (€)	EBITDA	Margin (%)	Debt	Debt/EBITDA (x)
IFRS 16 reported figures	1,200	360	30	900	2.50
Lease adjustment to EBITDA	0	40	3	0	(0.25)
Lease adjustment to debt	0	0	0	364	0.91
S&P Global Ratings' adjusted figures	1,200	400	33	1,264	3.16

211. The less indebted the company is, the higher the impact of a lease on its leverage ratio--the lease liability would be a larger component of total debt. However, there is little difference between a lease agreement and a service agreement in terms of cash flows and economic benefit to the mobile operator. We therefore aim to treat both contract types consistently when assessing the financial risk profile, which will maintain comparability between telecom companies' credit metrics.

212. Mobile network operators rely upon networks of radio towers, which support their business by

broadcasting signals to and receiving signals from the mobile devices of their customers. Traditionally, mobile operators have owned these assets. But over time, some operators have sold their towers to specialty infrastructure companies. They then rent space on the towers to place their antennas, which transmit and receive radio frequencies. This model typically employs a master lease agreement, whereby the mobile operator pays a fee in exchange for renting a specific space on the tower. The tower company also provides related maintenance. More recently, however, we've seen mobile operators sign long-term service agreements under which they have access to the full tower network but are not assigned specific spaces for their antennae. The tower company commits to manage deployment of the equipment to ensure an agreed level of service quality.

213. **IFRS treatment:** Under IFRS 16, leases will be recognized on the balance sheet and service contracts off balance sheet. Whether a contract is defined as a lease largely depends on the right to control an identified asset.

214. In a lease agreement, the mobile operator controls specific spaces on towers, which are used for their active equipment. This will be considered a lease contract because the asset is identified (designated space on specific towers) and the mobile operator remains in control of the identified asset. On its balance sheet, the mobile operator will recognize a right-of-use asset and lease liability based on discounted payments required under the lease. The mobile operator will not recognize the rental payments as an operating expense; instead, the asset will depreciate and interest is recognized based on the outstanding lease liability.

215. However, in a service agreement, the tower operator controls the towers and can move the mobile operator's equipment to alternative towers if it chooses. Therefore the contract is to provide a service and does not contain a lease under IFRS 16. Contract fees will be treated as operating expenses and will remain off the balance sheet.

216. If we were to follow IFRS 16, adopting service accounting would immediately and materially strengthen a mobile operator's leverage ratios, compared with a leased-tower scenario. But we do not believe the mobile operator's credit risk would have fundamentally changed, and think the more favorable financial comparison proposed under the new accounting standard would distort comparison across companies.

217. In deciding whether to adjust for service agreements, we sought to understand how a service arrangement substantively changes the operations and risk managed by mobile operators and tower companies alike. We think lease agreements already contain a service element because the tower company provides maintenance services in addition to the space on the towers. Service agreements could introduce new and material value-added services, such as:

- Active management of the equipment on a tower company's network to meet key performance indicator service requirements; or
- Implementation of new communication coverage requirements or protocols, for example, deployment of small cell stations and fifth generation (5G) mobile networks.

218. However, we do not view this as a certainty and anticipate scenarios where a service agreement tower portfolio remains a relatively static, mature asset. As new technologies and coverage requirements emerge, mobile operators may choose to retain responsibility for active network management in order to differentiate themselves from peers and gain a competitive advantage. Therefore, although we see the potential for additional services under a service agreement, we currently do not see the difference as material enough to warrant a different treatment compared with many of our telecom issuers that have lease agreements in place. We would need to see clear evidence of this in practice before treating tower service agreements differently from lease agreements. This would likely require measurable signs of active network monitoring and

management, manifest in detailed real-time analysis and active physical evolution, resulting in a more dynamic, less static network over time.

219. To facilitate global comparisons and benchmarking, our rating analysis incorporates quantitative adjustments to the reported financial statements of companies. These adjustments align a company's reported figures more closely with our view of underlying economic conditions and the credit risk inherent in its transactions and arrangements. Although we may adjust certain figures reported under applicable accounting principles, this does not imply that we challenge the company's application of those principles, the adequacy of its audit or financial reporting process, or the appropriateness of the accounting judgements made to fairly depict the company's financial position and performance for other purposes.

220. Our adjusted debt principle underpins our approach and drives many of the analytical adjustments we make. It results from our view that certain implicit financing arrangements are similar to debt. Depicting these transactions as debt--often in contrast to how a company reports them--affects not only the quantification of debt, but also the measures of earnings and cash flows we use in our analysis.

221. In general, items that we add to reported debt include on- and off-balance-sheet commitments to purchase or use of long-life assets (such as lease obligations) or businesses (such as deferred purchase consideration) where the company accrues benefits of ownership. We typically view sale and leaseback transactions as a form of financing. If we can, we capitalize the entire sale amount to debt, even if the NPV of future lease payments is a lower figure.

222. Under IFRS, if a mobile operator sells its towers to a tower company and then enters into a service agreement with that company, it has not entered into a sale and leaseback transaction because the service agreement does not meet the definition of a lease under IFRS 16. IFRS considers that the tower operator controls the network because it has "substantive substitution rights" to the asset.

223. By contrast, we do not believe this feature alone is sufficient to completely override our view that the transaction has an implicit financing component. This sort of transaction changes the mobile operator's situation. Pre-transaction, it owned and used the network of radio towers to generate cash flows. Post-transaction, it still makes use of the network of radio towers to generate cash flows, but it receives cash upfront in exchange for regular, fixed, and non-cancellable deferred payments (like a lease). In our view, the transaction does not clearly improve the fundamental financial risk profile, but the IFRS expense accounting treatment implies such an improvement by reducing its leverage. The same would be true if a mobile operator switched from a lease agreement to a service agreement or signed a service agreement with no prior access to the towers in lieu of buying or leasing them.

224. This guidance specifically addresses the tower master service agreement contract and the telecom sector, based on their unique characteristics. There are instances of other transactions and arrangements that share some features of the tower master service agreement, but where we don't make a debt adjustment. For example, some utilities spun off their transmission networks and then entered into service contracts for the transportation/transmission of gas and electricity. However, these utilities do not pay the service providers under a bilateral contract in the same way that mobile operators pay tower companies. Instead, the utility bills its retail customers and allocates a portion of the revenues to distribution, transmission, and suppliers, on a regulated basis.

225. If disclosures in the financial statements lack sufficient detail, we may face practical challenges in adjusting the debt of mobile operators that use tower service agreements. However, this is a familiar issue. We frequently estimate our analytical adjustments based on additional information provided by issuers. For example, we seek information from issuers regarding the amount of cash

and liquid investments that they cannot access at short notice to repay debt, and use this information to apply a haircut to our surplus cash figure.

226. We acknowledge that we have decided to adjust for tower service agreements based on the small sample size and short track record of such agreements to date. In time, if tower companies build a track record of active network management under these agreements, such that the service portion of the contract is demonstrably its overriding feature, we could change our view. This could lead us to treat tower service agreements as a service and reflect them as an expense, either in whole or, if we have sufficient detail regarding the service portion of the contract, in part.

Transportation cyclical industry

227. **Purchase commitments to partner entities providing transportation services:** In some cases, companies may contract with other entities to provide transportation services using those other entities' own equipment. In cases where the payments under such contracts are largely fixed and represent mostly a substitute for owning or renting equipment, we will capitalize the entire amount of the committed payments. Examples include time charters of ships with fixed payments that are mostly for ownership and, to a lesser extent, crewing costs. Where the contracted payments mostly represent reimbursement for other expenses, which may vary, we seek to estimate the proportion of the payments that represent a rental or ownership equivalent, and capitalize that. Examples include some airline capacity purchase agreements with partner regional airlines. In those agreements, a major airline may sublease regional aircraft to the regional airline (the ownership costs for which are accordingly already captured in the major airline's financial statements). Alternatively, the regional airline may provide its own aircraft. If the major airline nonetheless includes those indirect regional aircraft ownership costs as part of its own lease commitments, our capitalizing leases covers this. Where the major airline does not include the indirect regional aircraft ownership costs in its own lease commitments, we seek to estimate the proportion of the capacity purchase agreement that represents ownership costs. Non-ownership costs, which can be substantial, include labor and fuel, the latter a pass-through cost that can vary significantly over time.

Transportation infrastructure

228. **Service concession arrangements:** We make the following adjustments to the reported financials of transportation infrastructure companies operating under concessions:

- These companies generally report revenues from works and improvements to concession assets under the current interpretation of IFRS for service concession arrangements (IFRIC 12). This does not affect reported EBITDA, operating profit, or cash, because a corresponding operating cost is reported. We exclude these items from reported revenues and the cost of goods sold.
- In addition, when a transportation infrastructure company operating under a concession agreement receives fixed or guaranteed revenues according to IFRIC 12, the company generally does not report this as revenue on its income statement. When this income corresponds to a cash payment, we include it in revenues and EBITDA.

229. Data requirements:

- The amount of revenues and costs from works and improvements to infrastructure assets that are grossed up in the income statement.

- The amount of guaranteed income that is classified as interest income rather than revenues.

230. Calculations:

- Revenues and cost of goods sold or operating expenses. We exclude the amount of revenues and costs from works and improvements to infrastructure assets that are grossed up in the income statement.
- Revenues and EBITDA. We add the amount of guaranteed income classified as interest income rather than revenues.

231. **Inflation linked debt:** Some companies in the transportation infrastructure sector issue significant amounts of inflation-linked debt. Inflation-linked debt usually has a long tenor (20-30 years), and a low annual cash coupon (e.g., 1%-3%) which, without indexation, would usually represent a below-market cost of debt at issuance for the issuer, as it only reflects real term interest rates.

232. A distinct, typical feature of inflation-linked debt is the deferral of indexation payments to maturity. We view the accrual of principal indexation as a partial non-cash coupon. Deferral of its payment does not mean that this debt is any cheaper; simply, a portion of its periodic cost, which may be substantial, is being deferred to maturity.

233. We typically apply a charge for the indexation of principal for inflation-linked debt in our FFO calculation. We believe this approach better captures the after-interest cash flow the company's operations generate, including the full cost of the debt used to finance those operations. Where companies have not disclosed the amount of principal indexation, we may estimate the adjustment.

234. No adjustment is typically required to be made to reported debt if this includes the effect of the indexation component (the deferred interest portion) on a cumulative, compounded basis.

235. Where possible we make similar adjustments where companies use derivatives to synthetically convert debt into inflation-linked debt. This can require deducting from FFO the inflation payable portion of an inflation-linked swap and adding to debt the portion of the derivative's fair value that corresponds to the cumulative deferred interest.

236. **Provisions for future maintenance:** Under most concession arrangements, companies have contractual obligations to maintain the infrastructure to a pre-specified level of service and/or to restore the infrastructure to a particular condition before giving it back to the grantor. These obligations may take different forms ranging from routine repair costs to major lifecycle overhauls.

237. Routine repair costs are expensed as incurred in the income statement and classified as operating cash flows in the cash flow statement.

238. For longer term, major maintenance obligations that affect multiple years, the company recognizes a provision for the estimated NPV of future cash outflows under most accounting standards. Changes in the provision are reflected in the income statement (usually within reported operating income) systematically over the corresponding number of years. The cost recognition therefore significantly diverges from the related cash flows. When the maintenance obligation is fulfilled, the spending may be classified as either operating or investing cash flows in the cash flow statement.

239. To allow for globally consistent and comparable financial analyses, we view this long-term maintenance spending as more akin to capital expenditures (investing cash flows) and the related costs as non-operating in nature. We do not view the year-end provision as debt-like.

240. Data requirements:

- Long-term maintenance related income statement charge or reversal during the year, which we treat as non-operating.
- Amount of maintenance cash out-flows during the year.

241. Calculations:

- Add (or subtract) the long-term maintenance related income statement charge (or reversal) from the respective metrics such as operating income, before and after depreciation and amortization.
- Reclassify the amount of maintenance cash out-flows to capital expenditures if reported as operating cash flows.

RELATED CRITERIA AND RESEARCH

Related Criteria

- Corporate Methodology: Ratios And Adjustments, April 1, 2019

Related Research

- Criteria And Guidance: Understanding The Difference, Dec. 15, 2017

This report does not constitute a rating action.

This article is a guidance document for Criteria (Guidance Document). Guidance Documents are not Criteria, as they do not establish a methodological framework for determining Credit Ratings. Guidance Documents provide guidance on various matters, including: articulating how we may apply specific aspects of Criteria; describing variables or considerations related to Criteria that may change over time; providing additional information on non-fundamental factors that our analysts may consider in the application of Criteria; and/or providing additional guidance on the exercise of analytical judgment under our Criteria.

Our analysts consider Guidance Documents as they apply Criteria and exercise analytical judgment in the analysis and determination of Credit Ratings. However, in applying Criteria and the exercise of analytic judgment to a specific issuer or issue, analysts may determine that it is suitable to follow an approach that differs from one described in the Guidance Document. Where appropriate, the rating rationale will highlight that a different approach was taken.

Contact List

ANALYTICAL CONTACTS

Leonard A Grimando
New York
(1) 212-438-3487
leonard.grimando@spglobal.com

ANALYTICAL CONTACTS

Imre Guba
Madrid
(44) 20-7176-3849
imre.guba@spglobal.com

ANALYTICAL CONTACTS

Sam C Holland, FCA
London
(44) 20-7176-3779
sam.holland@spglobal.com

ANALYTICAL CONTACTS

Shripad J Joshi, CPA, CA
New York
(1) 212-438-4069
shripad.joshi@spglobal.com

ANALYTICAL CONTACTS

Raam Ratnam, CFA, CPA
London
(44) 20-7176-7462
raam.ratnam@spglobal.com

ANALYTICAL CONTACTS

Scott E Zari, CFA
Chicago
+ 1 (312) 233 7079
scott.zari@spglobal.com

ANALYTICAL CONTACTS

Mehul P Sukkawala, CFA
Singapore
(65) 6239-6337
mehul.sukkawala@spglobal.com

ANALYTICAL CONTACTS

Diego H Ocampo
Buenos Aires
(54) 114-891-2116
diego.ocampo@spglobal.com

METHODOLOGIES CONTACTS

Peter Kernan
London
(44) 20-7176-3618
peter.kernan@spglobal.com

METHODOLOGIES CONTACTS

Marta Castelli
Buenos Aires
(54) 114-891-2128
marta.castelli@spglobal.com

METHODOLOGIES CONTACTS

James A Parchment
New York
(1) 212-438-4445
james.parchment@spglobal.com

METHODOLOGIES CONTACTS

Veronique Chayrigues
Paris
(33) 1-4420-6781
veronique.chayrigues@spglobal.com

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Key Credit Factors For The Regulated Utilities Industry

Primary Credit Analysts:
Richard Creed, Melbourne (61) 3-9631-2045; richard.creed@standardandpoors.com
Barbara A Eiseman, New York (1) 212-438-7666; barbara.eiseman@standardandpoors.com
Vittoria Ferraris, Milan (39) 02-72111-207; vittoria.ferraris@standardandpoors.com
Sergio Fuentes, Buenos Aires (54) 114-891-2131; sergio.fuentes@standardandpoors.com
Gabe Grosberg, New York (1) 212-438-6043; gabe.grosberg@standardandpoors.com
Parvathy Iyer, Melbourne (61) 3-9631-2034; parvathy.iyer@standardandpoors.com
Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@standardandpoors.com
Andreas Kindahl, Stockholm (46) 8-440-5907; andreas.kindahl@standardandpoors.com
John D Lindstrom, Stockholm (46) 8-440-5922; john.lindstrom@standardandpoors.com
Nicole D Martin, Toronto (1) 416-507-2560; nicole.martin@standardandpoors.com
Sherman A Myers, New York (1) 212-438-4229; sherman.myers@standardandpoors.com
Dimitri Nikas, New York (1) 212-438-7807; dimitri.nikas@standardandpoors.com
Ana M Olaya-Rotonti, New York (1) 212-438-8668; ana.olaya-rotonti@standardandpoors.com
Hiroki Shibata, Tokyo (81) 3-4550-8437; hiroki.shibata@standardandpoors.com
Todd A Shipman, CFA, New York (1) 212-438-7676; todd.shipman@standardandpoors.com
Alf Stenqvist, Stockholm (46) 8-440-5925; alf.stenqvist@standardandpoors.com
Tania Tsoneva, CFA, London (44) 20-7176-3489; tania.tsoneva@standardandpoors.com
Mark J Davidson, London (44) 20-7176-6306; mark.j.davidson@standardandpoors.com

Criteria Officer:
Mark Puccia, New York (1) 212-438-7233; mark.puccia@standardandpoors.com

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Key Credit Factors For The Regulated Utilities Industry

*(**Editor's Note:** This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.

2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," Dec. 9, 2010).

SUMMARY OF THE CRITERIA

4. Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage

assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

IMPACT ON OUTSTANDING RATINGS

5. These criteria could affect the issuer credit ratings of about 5% of regulated utilities globally due primarily to the introduction of new financial benchmarks in the corporate criteria. Almost all ratings changes are expected to be no more than one notch, and most are expected to be in an upward direction.

EFFECTIVE DATE AND TRANSITION

6. These criteria are effective immediately on the date of publication.

METHODOLOGY

Part I—Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11 We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15 As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

18. The analysis of competitive position includes a review of:

- Competitive advantage,
- Scale, scope, and diversity,
- Operating efficiency, and
- Profitability.

19 In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

24. Regulatory stability:

- Transparency of the key components of the rate setting and how these are assessed
- Predictability that lowers uncertainty for the utility and its stakeholders
- Consistency in the regulatory framework over time

25 Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

26. Financial stability:

- Timeliness of cost recovery to avoid cash flow volatility
- Flexibility to allow for recovery of unexpected costs if they arise
- Attractiveness of the framework to attract long-term capital
- Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

27 Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)		
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e.,

extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37. The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41. In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if

operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,
- Return on capital (ROC), and
- Return on equity (ROE).

49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53 We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least

seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)

58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio.The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is

employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

66. Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- Analytically determined risk factor.

- Calculations:
- Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the

debt.

- An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).

- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69 For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

71. Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.

- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume

that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.

- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;

- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Appendix--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

RELATED CRITERIA AND RESEARCH

- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

(And watch the related CreditMatters TV segment titled, "Standard & Poor's Highlights The Key Credit Factors For Rating Regulated Utilities," dated Nov. 21, 2013.)

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to Attorney General's Third Data Requests
Dated March 17, 2020

Case No. 2020-00016

Question No. 9

Witness: David S. Sinclair

Q-9. Provide the current price the Companies are receiving for RECs with regard to solar power produced at the Brown solar facility. Also identify that market.

a. State whether the Companies intend to utilize the same market for RECs that would be earned under the proposed PPA.

A-9. See response to PSC DR2-5 (d)(2). In 2019, the Companies received revenue from REC sales at an average of $9.55 per REC. Below is a table of REC sales from the past twelve months up to and including March 17, 2020. The price for these REC sales averaged $10.26 per REC. For RECs, there is not an exchange-type market like the Intercontinental Exchange ("ICE"). The Companies sell RECs in a bilateral market. Previous counterparties have included REC brokers as well as individual utilities seeking to procure RECs to satisfy their obligations for their states' renewable portfolio standard requirements. Currently, RECs produced in Kentucky are likely to be sold for use to comply with Ohio RPS obligations.

Brown REC Sales		
Trade Date	**Volume**	**Price**
3/15/2019	1,415	$ 22.25
5/1/2019	823	$ 25.00
7/16/2019	5,000	$ 10.75
8/22/2019	50	$ 9.00
9/17/2019	3,558	$ 6.15
10/29/2019	1,997	$ 7.00
12/12/2019	754	$ 8.50
12/13/2019	1,200	$ 8.25
12/13/2019	1,485	$ 8.25
1/13/2020	1,466	$ 8.75
3/17/2020	1,610	$ 9.35

In the absence of any other REC market developments, the Companies intend to continue to utilize a bilateral approach for selling the RECs received from the 25% of the PPA assigned to all customers.

Louisville Gas and Electric Company and Kentucky Utilities Company
Response to Attorney General's Third Data Requests
Dated March 17, 2020

Case No. 2020-00016

Question No. 10

Witness: Counsel

Q-10. Explain whether ratepayers would be held harmless from any potential claims arising from land erosion / subsidence, or other environmental issues at the site of the proposed solar facility.

A-10. While the exposure of LG&E and KU to such claims would be remote for the reasons noted below, the Power Purchase Agreement for which LG&E and KU seek approval ("PPA") requires Seller to indemnify, pay, defend, and hold harmless LG&E and KU from and against claims for damages resulting from, among other things, (1) acts or omissions by the seller in the installation or operation of the proposed generation facility and (2) breaches by Seller of its obligations under the PPA. Those obligations include constructing and maintaining the proposed generation facility in accordance with applicable laws, applicable permits, and industry standards. Accordingly, to the extent land erosion / subsidence, or other environmental issues at the site of the proposed solar facility results from such circumstances, seller would be required to indemnify, hold harmless, and, perhaps most importantly, defend LG&E and KU from resulting claims.

Please note that neither LG&E nor KU will own, construct, operate, or maintain the proposed generating facility, making it difficult to see a viable basis for any claim against either LG&E or KU in connection with conditions at the site. As previously indicated in responses to AG 2-4, AG 2-5, AG 2-6, AG 2-7, and AG 2-20, the Companies will not own or lease any property for this solar facility. Section 17.1 (B) indemnifies the Companies against all claims from the Seller. However, in the event such a claim is brought, Seller would be required to defend LG&E and KU against it and indemnify LG&E and KU with respect to the results. Also note that the PPA requires Seller to maintain significant specified insurance coverage under policies naming LG&E and KU as additional insured.

For these reasons, the proposed PPA does not present an unreasonable risk to ratepayers for the potential claims referenced in the request for information.