COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	))))))))))	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)))))))))))	**CASE NO. 2020-00350**

TESTIMONY OF
GREGORY J. MEIMAN
VICE PRESIDENT, HUMAN RESOURCES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

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Q. Please state your name, position and business address.

A. My name is Gregory J. Meiman. I am Vice President, Human Resources for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"), (collectively, the "Companies") and an employee of LG&E and KU Services Company ("Service Company"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. A complete statement of my work experience and education is contained in the Appendix attached hereto.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes. I submitted written direct testimony in Case No. 2014-00002,[1] while serving in my prior position as Director of Corporate Tax and Benefit Plan Compliance for the Companies. In the Companies' 2016 rate cases,[2] I appeared at the evidentiary hearing and answered questions in my then and still current capacity as Vice President, Human Resources for the Companies. In the Companies' 2018 rate cases, I submitted written direct and rebuttal testimony and testified at the evidentiary hearing.[3]

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[1] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*, Case No. 2014-00002, Direct Testimony of Gregory J, Meiman (Ky. PSC Jan 17, 2014).

[2] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370; *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00371.

[3] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Rates*, Case No. 2018-00294, Testimony of Gregory J. Meiman (Ky. PSC Sep. 28, 2018) and Rebuttal Testimony of Gregory J. Meiman (Ky. PSC Feb. 22, 2019); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Testimony of Gregory J. Meiman (Ky. PSC Sep. 28, 2018) and Rebuttal Testimony of Gregory J. Meiman (Ky. PSC Feb. 22, 2019).

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to inform the Commission of the overall reasonableness of the compensation and benefits structure we offer to current and prospective employees. More specifically, I will: (1) explain the Companies' compensation and employee benefit expenses and sponsor a schedule required by 807 KAR 5:001, Section 16, as set forth at Tab 60 of the filing requirements attached to the applications; (2) describe the results of Willis Towers Watson's ("WTW") Target Total Cash Compensation Study which examines the Companies' mix of base and incentive pay compared to market; and (3) describe the results of the studies prepared by Mercer (a national employee benefits consulting firm) and WTW which, respectively, examine the Companies' retirement and welfare benefits offerings compared to market and the overall value of the Companies' retirement benefits. My testimony shows that the Companies diligently manage compensation and benefit offerings so that they are reasonable, prudent, market competitive, and, therefore, should be fully recovered in rates.

Q. Are you sponsoring any schedules required by the Commission's regulation 807 KAR 5:001 Section 16?

A. Yes. I am sponsoring Section 16(8)(g), analyses of payroll costs including schedules for wages and salaries, employee benefits, payroll taxes, straight time and overtime hours, and executive compensation by title.

I. WORKFORCE AND TOTAL CASH COMPENSATION

Q. Please describe the general composition of the Companies' workforce.

A As of September 30, 2020, a total of 3,585 employees (including a small number of temporary employees) perform work for the Companies through employment by KU, LG&E, or the Service Company. More specifically, KU has 890 employees, LG&E has 1,035 employees, and the Service Company has 1,660 employees. Of the total amount, 766 are union employees.

Q. What sort of expertise and knowledge are required by the Companies' employees?

A. A large segment of our employment force requires specialized and technical skills for their work involving electric generating plants, gas facilities, transmission substations, and electric and gas transmission and distribution equipment. Our employees must have the requisite knowledge and technical skills to plan, design, operate, and maintain electric generating plants, high voltage equipment, gas storage fields, and gas lines in a manner that provides safe and reliable service. They must also have an aptitude for continuous learning and training on computer software systems.

The operation and maintenance of a field office and a customer call center requires detailed knowledge of all aspects of customer service. Field office and call center employees must understand the characteristics of electric generating and delivery service, metering, billing and collection processes, and various other customer service matters. At the corporate level, highly skilled managers, attorneys, engineers, accountants, computer hardware and software professionals, cyber security experts, and other highly trained professionals are needed to support the employees who are directly responsible for generating and delivering utility service to the Companies' customers. Competition for such employees has always been and will continue to be fierce.

Q. Can you elaborate on the skills required of employees, the training they must complete to develop those skills, and the cost of that training?

A. Yes. When recruiting for talent, the Companies look for the required skills or the ability to acquire these skills (evaluated via pre-employment testing) in order to provide safe and reliable service to our customers. Understanding it takes a minimum of three and in some areas as many as five years of training before most of our field employees can work independently, it is critically important to hire the right candidate.

Employee training is an investment. If the right hiring decision is not made, the Companies' overall turnover costs are increased, leading to inefficiencies and a lack of productivity. Therefore, the hiring decision is not taken lightly. Being market competitive and providing a culture of engagement and growth are critical for retention. For example, the Companies, other utilities, municipals, and co-ops recruit for line technicians from Somerset Community and Technical College and Madisonville Community College. Our safety record, along with a reputation for operational excellence has made us an employer of choice among the skilled trades at those institutions and other areas where we recruit.

Q. Please explain the overarching goal of the Companies in determining the level of compensation and benefits offered to employees.

A. It is imperative that the Companies offer a *total* compensation and benefits package to existing and prospective employees that is competitive within the utility sector. When we set compensation and benefit levels, we do not look at any one part of compensation or a single benefit offering in isolation. Instead, by any rational measure, the entire compensation and benefits package should be evaluated on an *aggregated* basis to determine whether the total package is aligned with utility market medians. That is exactly how we strive to ensure compensation and benefit levels are set at a reasonable level. Likewise, when existing and potential employees consider employment with the Companies, they do not look solely at base compensation, retirement benefits, healthcare coverage, or any other single element of compensation or benefits. Instead, they rationally consider all aspects of compensation and benefits in making their employment decisions. The Companies set compensation and benefit levels in exactly the same way.

While one element of our compensation and benefits package may be slightly above market median, another element may be slightly below. Those variances to market are unimportant and frankly irrelevant as long as the overall package offered to employees is in line with market median levels. In our experience, offering a competitive package of compensation and benefits is precisely how the Companies have maintained the excellent, dedicated, and productive workforce they have, which, of course, leads directly to providing value to customers. The Companies' excellent operational results, described in Mr. Thompson's and Mr. Bellar's testimonies, could not be achieved without such a workforce.

Just as the Companies and employees do not overly emphasize any one element of compensation and benefits in making rational decisions, any objective analysis should not cherry pick any compensation or benefit levels that are above market as long as the entire package of compensation and benefits on balance is reasonable. As set forth below and in independent studies the Companies have provided, it is clear that the entire package is competitive in the utility market, which is the appropriate comparator and is therefore reasonable. At bottom, a competitive compensation and benefits package is essential to meet the Companies' obligation to provide safe, reliable, and adequate service and to do so efficiently and productively.

Q. Would customers suffer if the Companies' employees are not provided competitive compensation and benefits?

A. Yes, definitely. If compensation and benefits are not at market levels in the utility sector, customers would suffer substantial negative consequences through unreliable service and higher costs of service. Many of our employment positions require lengthy apprenticeships and training to learn the skills needed to perform technical or skilled work independently and safely. The delivery of electricity and gas is inherently dangerous. Our society demands that those entrusted with this critical public function exercise the highest standard of care. The expense incurred to hire and train new employees and the loss of productivity realized through high turnover rates would negatively affect the ability of the Companies to serve customers at expected levels and increase our cost of providing the service.

To maintain our current high levels of service, we must avoid high turnover by attracting and retaining highly skilled employees. Our existing compensation and benefits package allows us to avoid high turnover. This means that we can serve customers while keeping our costs, and therefore our rates, as low as reasonably possible.

Q. Please explain the Companies' compensation philosophy.

A. The Companies' compensation philosophy and practices continue to be grounded in the goal of producing sustainable operating results by attracting and retaining talented and experienced individuals. Compensation reflects the long-established commitment to a "pay-for-performance" model while targeting the market median. We want our compensation to be market-based and competitive while also driving performance.

The Companies have a written compensation policy that has been in effect since 1997 which is reviewed on a regular basis by Human Resources. Compensation decisions made under this policy are supported by various levels of approval. Individual salary recommendations made under the Companies' written compensation policy are reviewed and approved by the manager, next level manager, and Human Resources, thus ensuring base salaries are competitive based on the nature and responsibilities of the employee's position and are fair relative to the pay for other similarly-situated positions within the organization. In addition, the annual salary increase budget is included in the Companies' budgeting process which is reviewed and approved by the LG&E and KU Boards.

Using external market compensation data at the 50th percentile of the national general or utility industry, job pay midpoints are established. Salary range minimums and maximums are based on 70% and 130% of the 50th percentile midpoint, respectively. Individual employee compensation is then managed within this competitive range. As detailed in the 2020 WTW *Target Total Cash Compensation Study*, compensation is considered competitive if it is within +/- 10% of the midpoint when considering factors that include performance, time in position, tenure, education, and experience.

Q. Describe how the Companies undertake the process of setting the compensation and benefit levels for their employees as that information is proposed at Tab 60 of the filing requirements.

A. Certainly. Although Daniel K. Arbough's testimony explains the process by which labor costs are budgeted and then used in the forecasted test period, I can provide information on how the Companies set their compensation and benefit levels. On an annual basis, the Companies rely on benchmark information in calibrating the level of certain components of compensation and benefits arrangements.

With regard to compensation, total compensation paid to employees is comprised of base compensation and incentive compensation. Base pay adjustments are awarded, if any, based on a combination of factors, including the employee's individual performance, performance relative to their peers, the position of their salary within the salary range and as compared to their peer group and the size of the annual salary budget. Incentive compensation is provided via the Companies' Team Incentive Award ("TIA") Plan which is attached as Exhibit GJM-1. As described above, the Companies strive to ensure that total compensation paid is consistent with the market and rely on third-party benchmarking and salary planning surveys from the energy services and general industries to do so.

Q. Although the Companies routinely rely on such benchmarking and salary planning surveys in setting total compensation, have they commissioned a study to look specifically at their total compensation relative to market?

A. Yes. The Companies commissioned WTW to provide a separate and independent study that specifically examines the Companies' compensation levels. They did so to provide the Commission with the most current and specific information possible on those compensation levels. The study is attached at Tab 60 of the filing requirements. It is entitled 2020 "*Target Total Cash Compensation*" because it studied all cash compensation paid to the Companies' employees and measures that total cash compensation relative to market.

Q. Who is WTW?

A. WTW, which traces its roots back to 1934, is a global consulting company that provides an array of services to businesses. WTW advises organizations on all aspects of their compensation programs with the goal of paying employees appropriately and enabling organizations to attract, retain, and motivate employees efficiently and cost-effectively. Typical areas of compensation consulting assistance include pay philosophy development, variable or incentive compensation plan design, total compensation benchmarking, and compensation structure development.

Q. Please describe the results of the WTW study.

A. The WTW *Target Total Cash Compensation Study* found the following:

- When compared to available published survey data, the Companies' projected and actual base salary budgets are closely aligned with market median levels;
- The Companies' use of base salary and target incentive compensation as its primary pay vehicles for employees is consistent and aligned with market pay vehicles used by utility and general industry peers. Likewise, when compared to available published survey data, the Companies' compensation levels fall within the competitive range of the market 50th percentile for base salary and target total cash compensation, and, in fact, are actually 3.1% below market median when compared to utilities; and
- When compared to available published survey data, LG&E's and KU's pay mix (base salary and target incentive compensation) generally places less emphasis

on short-term at-risk compensation than peers, but approximates market practice overall.

The WTW report confirms that our compensation-setting philosophy and process has resulted in exactly what we strive to achieve -- that with the inclusion of incentive compensation, our total compensation levels are very closely aligned with market medians. And the converse is also true in that without incentive compensation as part of the total compensation, the Companies' compensation levels would fall well below market and therefore jeopardize our ability to attract and retain an adequate workforce.

Q. Please describe the Companies' TIA Plan.

A. The TIA Plan is a long-standing "at risk" component of pay in which a part of an employee's annual cash compensation is considered "at risk" and earned only if certain objectives are met. In other words, if certain performance results are achieved, a cash incentive award will be earned. The actual amount of the award depends upon the achieved results. The TIA Plan, which has been in place since the 1990s, was developed to motivate, focus, and direct employees toward the achievement of strategic goals and is part of an overall corporate strategy to attract and retain skilled employees by providing competitive financial awards that are commensurate with the employees' talents, teamwork, and contribution. It is intended to set high expectations and motivate participants to achieve higher levels of performance, communicate and focus on critical success measures, reinforce desired behaviors including increased focus on the customer by motivating employees to lower costs and achieve higher reliability and customer satisfaction results, and bolster an employee ownership culture and reward results if achieved.

Q. Do you believe incentive compensation pay should be recovered in rates?

A. Absolutely. The Companies' incentive compensation expense is reasonable, and it should be recovered in full for several reasons. First, I believe that incentive compensation aligns the interests of our employees with those of our customers. Through the measures used in the plan (customer satisfaction, customer reliability, cost control, and safety) employees' compensation depends upon an unwavering focus on the customer. Customers benefit from this focus. Second, the WTW study shows that the total compensation paid to employees, which includes both base salary and incentive compensation, is reasonable and consistent in the competitive marketplace. Without incentive compensation, the compensation paid would fall below market rates and hinder the Companies' ability to attract and retain a qualified workforce. Third, the WTW study shows that the relative mix of base salaries and incentive compensation in determining overall cash compensation is reasonable and at a competitive level when compared to the competitive marketplace. In other words, the amount of incentive compensation offered is consistent with the marketplace levels. Finally, in the competitive market for talent, employees consider all aspects of compensation and benefits – including incentive compensation – in making employment decisions.

Q. How are TIA payments determined?

A. All eligible employees have a TIA target award. The criteria for and calculation of those awards for 2020 are set forth in the TIA Plan. As set forth in that document, the target awards are:

Employee Status	Target Award
Non-Exempt and Hourly/Bargaining Unit	**6% of Annual Earnings**
Exempt Individual Contributors	**9% of Base Salary**
Managers	**14% of Base Salary**
Senior Managers	**25% of Base Salary**

For an individual employee in 2020, the calculation of incentive compensation is determined using the following objectives and percentages: (1) customer satisfaction (15%); (2) customer reliability (15%); (3) cost control (15%); (4) corporate safety (15%); and (5) individual and/or team effectiveness (40%).[4]

Q. Please describe the performance objectives of customer satisfaction, customer reliability, cost control, corporate safety, and individual and team effectiveness.

A. Certainly. Those descriptions are:

- Customer Satisfaction is measured by the Companies' performance ranking within its peer group. The Companies' market research vendor contacts randomly selected customers and customers from peer group companies and asks them about overall satisfaction with their respective utilities.
- Customer Reliability is measured by the System Average Interruption Duration Index which is a well-known industry metric for service reliability.
- Cost Control is measured by non-fuel operation and maintenance expenses in accordance with generally accepted accounting principles as published in the Companies' annual Form 10-K filings with the Securities and Exchange Commission.

[4] See Exhibit GJM-1, p. 4.

- Corporate Safety is measured by using recordable injury rates, illness rates, and "days away, restricted and transfer" rates, commonly referred to as "DART" rates.
- Individual and Team Effectiveness measures ensure that employees are collectively working to achieve strategic business goals. Individual goals will vary by the individual employee and by department. They support respective department and line of business objectives and are overall customer focused.

As one can see, like many incentive compensation plans offered by employers, the TIA plan seeks to reward high-performing employees for successful efforts in the areas of customer service, cost control, and individual and team effectiveness. The TIA Plan "provides an opportunity for eligible employees to share in the added value they create through superior performance."[5] Without question, it also aligns our employees with our customers, while helping to attract and retain quality employees by ensuring their total compensation is consistent with the market.

II. RETIREMENT AND WELFARE BENEFITS

Q. Please describe the Companies' philosophy with respect to retirement and welfare benefits.

A. As discussed above, the Companies' overarching goal is to offer a *total* package of compensation and benefits that is competitive to market. Because benefits are essential to attracting and retaining an adequate workforce, it is imperative that the overall benefits package be market competitive. Therefore, when we set retirement and welfare benefit levels, we do not look at each individual benefit or segment of the

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[5] See Exhibit GJM-1, p. 1.

employee population in isolation and neither should any objective analysis. Instead, we strive to ensure that the aggregated package of benefits, including both retirement and welfare benefits, is aligned with market for the aggregate workforce.

Q. Please describe the retirement benefits the Companies offer to employees.

A. In addition to providing a compensation package that is consistent with the market, the Companies also offer certain retirement and welfare benefits to their employees at levels that ensure the entire benefits "package" is consistent with the market. We believe that offering a competitive benefits package is just as important as compensation to attract and retain an adequate workforce. The Companies' retirement benefits include:

(1) A traditional defined benefit pension plan ("DB Plan") available to those who were hired prior to January 1, 2006 which was closed to all those hired after that date. Under the DB Plan, pension payments are made by the Companies to eligible retirees based on a mathematical formula and actuarial calculations.

(2) A Retirement Income Account which is a defined contribution plan ("DC Plan") available to those who were hired or rehired on or after January 1, 2006. Under the DC Plan, the Companies make annual contributions to an employee' Retirement Income Account. The amount of those payments is calculated using a percentage of compensation which percentage can range from three to seven percent depending on the employee's years of service.

(3) A company match by which the Companies will match 35% of an employee's voluntary deferred compensation amount up to a maximum of 6 percent (and subject to IRS limits) within the employee's 401(k) account for employees hired

before January 1, 2006, as of January 1, 2020. For employees hired on or after January 1, 2006, 70% of an employee's voluntary deferred compensation amount up to a maximum of 6 percent (and subject to IRS limits) within the employee's 401(k) account.

To be clear, each employee may participate in the Companies' Savings Plan. For employees hired on or after January 1, 2006, the Savings Plan is comprised of item number (2) above, and, if the employee makes voluntary deferred compensation contributions, then the stated match in item number (3) above as well. For employees hired before January 1, 2006, the Savings Plan is comprised of item number (3) above at the *reduced* matching level, if the employee makes voluntary deferred compensation contributions. The Companies implemented the *reduced* matching level (from 70% to 35%) for pre-January 1, 2006 employees effective January 1, 2020.

Q. Who is Mercer?

A. Mercer is a nationally and globally known entity offering a wide array of services to employers including providing advice, technology, and benchmarking analyses to help organizations meet the health, welfare, and career needs of their workforces. The Companies commissioned Mercer to assess their retirement and welfare benefits offerings relative to market so that the Commission will have current, accurate, and robust data concerning the Companies' overall benefits offerings.[6]

Q. Did Mercer look at just a single element of benefits in reaching their conclusions?

A. No, not at all. As I stated above, from an employment and ratemaking perspective, any objective analysis must examine the aggregate package of retirement and welfare

[6] Mercer's benefits study is attached to Tab 60 of the filing requirements.

benefits to determine whether that package is aligned with market. Mercer did what the Companies, current employees, and prospective employees do and what a rational analysis requires; they examined the *aggregate* package of retirement and welfare benefits to determine whether that package is aligned with market.

Q. What did Mercer conclude?

A. The Mercer *Benefits Study* shows that the combined (retirement and welfare) package of benefits is slightly below the range of market competitiveness of plus or minus five percent of median within the utility sector. It proves that the Companies' efforts to ensure that welfare benefits are aligned with the utility market have been successful.

Q. What else does the Mercer *Benefits Study* show?

A. The Mercer *Benefits Study* indicates:

- When evaluating benefits programs, it is important to look at the positioning of all benefits in aggregate as benefit plans are designed holistically and not in finite parts;
- It is important to examine benefit levels in the context of total remuneration (compensation and benefits) as compensation and benefits are designed and assessed in tandem; and
- The Companies total package of benefits is aligned with and slightly below utility market median with an Index 93 score (consistency with market being defined as anything between an Index score of 95-105).

Q. Do you agree with the Commission's decision in the Companies' most recent rate cases in which the Commission excluded from rate recovery the employer-

provided 401(k) match amount made to employees who participate in the DB Plan?

A. No. In those cases, I do not believe there was sufficient weight to the Companies' efforts to control costs while maintaining a system of retirement benefits that will retain longtime employees who possess significant and invaluable knowledge and experience. The Companies have effectively managed costs related to their retirement plans by closing their DB Plan and offering employees hired on or after January 1, 2006 participation in their DC Plan. The overall approach of the Company is to manage the benefit programs covering the entirety of the workforce in a manner that is reasonable. Yet, the Commission found that absent reductions in benefits provided to those participating in the closed DB plans, the matches paid to those same employees were excessive. As stated above, after the last rate case, the Companies reduced the match for the employees hired prior to January 1, 2006. The goal of the reduction was to align the value of this element of the benefits program for all employees. Accordingly, the retirement benefits for the pre-2006 employees are now barely above the post-2006 employees, based on a study conducted by Willis Towers Watson.[7]

The revised approach demonstrates the reasonableness of that benefit and means that the full cost of the benefit should be recovered in rates. In fact, elimination of the remaining match would result in the value of the benefit for the pre-2006 employees being *lower* than that of the post-2006 employees.

Q. Please describe the welfare benefits the Companies offer to employees.

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[7] See the Willis Towers Watson *Retirement and Savings Plan Analysis* attached to Tab 60 of the filing requirements.

A. The Companies offer a package of welfare benefits that employers commonly provide to employees. The primary welfare benefits include the opportunity for employees and their families to participate in plans for medical care coverage, dental and vision coverage, life insurance coverage, and disability coverage.

Q. What principles do the Companies follow in offering and managing health benefits?

A. Our ultimate goal is healthy employees who strive to meet their best achievable health status. We try to partner with employees in establishing a culture of health by emphasizing health status knowledge, preventive care, and healthy lifestyles. It is critical to offer welfare benefits at market levels so that we can attract and retain a skilled and reliable workforce. At the same time, prudent cost control is a necessity which is why the Companies require cost increases to be shared between the Companies *and* employees and why the Companies take advantage of cost savings measures whenever possible.

Q. What steps have the Companies taken to control costs of the health benefits they offer?

A. The Companies continually look for more efficient ways to deliver service. The Companies took a major step in this regard when they decided to establish a dedicated medical clinic in 2020. The clinic, which is staffed and operated by a third-party entity, provides primary and occupational health care to employees. The addition of the clinic resources will enable us to manage health costs and maintain a high level of care to our employees and their spouses covered under the Company medical plan.

We continue to take steps to control prescription costs by participating in a Pharmacy Benefit Collective for the last several years. That effort ensures we are receiving the best possible terms and pricing for prescriptions.

Finally, the Companies work together with union and non-union employees in a continuous effort to stay abreast of health care issues. This occurs through the Health Care Task Force which is a broad-based employee group of union and non-union employees that meets regularly with the goal of maximizing healthcare coverage value while controlling costs. That group then provides suggestions to the Companies. One of the benefits of this practice is that it simplifies negotiations with unions over healthcare issues and provides the Companies with healthcare advocates across its workforce.

Q. What have the Companies done to encourage a healthier workforce and have those efforts been successful?

A. The Companies have taken many significant steps over the years in furtherance of their conviction that a healthy workforce is safer and more productive. This "wellness" goal led to the adoptions of a "Healthy for Life" premium structure that allows employees and covered spouses a reduction of $125 per month in their premiums if they complete four steps: (1) obtain and submit a biometric screening (waived in 2020 due to COVID-19); (2) complete a "well-being assessment" survey; (3) represent they are tobacco-free or complete a "Quit for Life" tobacco cessation program; and (4) complete an acknowledgment of preventative health measures they should consider.

The end result of these wellness initiatives is that, despite an environment in which others have seen healthcare costs increase significantly, the Companies total medical costs have only increased an average of 2.4% over the past five years which is better than the national trend which for this same period was 3.3%.

Q. Describe how the Companies ensure that their healthcare benefit offerings are consistent with market levels.

A. Since 2001, the Companies have participated in regional healthcare benchmarking surveys to ensure our medical benefits are in alignment with market. Our more recent survey comparisons now include national and local employers as well as utilities. Adjustments are made based upon Mercer's analysis of plan costs and their recommendation and plan design structure changes are made in order to keep benefits in line with benchmarks. Benchmark data, medical claim information, and medical trend data are utilized in structuring plan offerings and medical premiums. This effort occurs annually. In 2017, the Companies made significant plan design changes to align with benchmarking including increases to employees' out-of-pocket costs.

Of course, the decision to require employees to pay an increase in their out-of-pocket costs was not taken lightly. However, it is one of the most direct and effective ways to control these costs. The Companies do not look only at the premium, as it does not provide the total picture of employee cost sharing. Cost sharing is designed to encourage good consumer health care choices by providing opportunities for lower employee premiums and higher "out-of-pocket" costs at the point of service so that the consumers of health care services are paying for it.

For these "out-of-pocket" costs (which include premium sharing amounts, deductibles, co-insurance, and co-payments) for medical, dental, and vision employees are required to shoulder a significant portion of the total cost. For 2019, our employees' total out-of-pocket costs were 31.2% of the total medical and prescription costs. Employees are required to pay 100% of the premium for vision, supplemental life, and dependent life insurance coverage.

Q. Did the Companies also commission Mercer to review the Companies' welfare benefit offerings as they relate market levels?

A. Yes. As stated, the Mercer *Benefits Study* assesses the Companies' total employee benefits offerings, including both retirement and welfare benefits, in determining how those benefits compare to market in the utility sector in which the Companies compete for employees. Again, Mercer concluded that the Companies' total benefits package is consistent with utility market median with an Index score of 93.

Q. Do you have a conclusion and recommendation for the Commission?

A. Yes, as described in more detail above, the Companies' compensation, including base pay and incentive compensation, and its various retirement and welfare benefit offerings are critical to the Companies' ability to provide the service our customers expect and deserve. We take great care to ensure that compensation and benefits are reasonable and we have offered proof in this case that we have met our goal of providing a total compensation and benefits package that is aligned with market. I believe the Companies benefit and compensation programs are competitive with the market, reasonable, and necessary to attract, retain, and motivate the qualified employees that the Companies need to provide safe, reliable, and efficient services to LG&E and KU customers. Accordingly, I recommend that the Commission allow full rate recovery for these crucial components of operating our business.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Gregory J. Meiman**, being duly sworn, deposes and says that he is Vice President, Human Resources 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 foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gregory J. Meiman
Gregory J. Meiman

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

Judy Schooler
Notary Public

Notary Public, ID No. 603967

My Commission Expires:

July 11, 2022

APPENDIX A

Gregory J. Meiman
Vice President, Human Resources
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2562

Education

University of Louisville, Louis D. Brandeis School of Law, Juris Doctor,
Louisville, Kentucky 1986
University of Louisville, Bachelor of Science in Business Administration,
Louisville, Kentucky 1983

Professional Experience

LG&E and KU Energy LLC, Louisville, Kentucky

Vice President, Human Resources	2016 – present
Director, Corporate Tax and Benefit Plan Compliance	2013 – 2016
Senior Counsel and Executive Plans Specialist	2002 – 2012
Asst. General Counsel and Executive Plan Manager	2000 – 2001
Senior Counsel and Executive Plan Manager	1999 – 2000
Senior Corporate Attorney	1996 – 1999

Greenebaum Doll & McDonald PLLC, Louisville, Kentucky

Of Counsel	2001-2002

Providian Corporation, Louisville, Kentucky

Tax and Benefits Counsel	1988 – 1996

Welenken, Himmelfarb & Company, Louisville, Kentucky

Staff Accountant	1986 – 1988

Professional Memberships

Kentucky Bar Association
Louisville Bar Association
Kentucky Society of Certified Public Accountants
Certified Employee Benefits Specialist

Civic Activities

Louisville Ballet Board (2012-2018)
University of Louisville College of Business Board of Advisors

LG&E KU

TEAM INCENTIVE AWARD (TIA) PLAN

- Corporate Safety
- Customer Satisfaction
- Cost Control
- Customer Reliability
- Individual and Team Effectiveness

TIA

Eligible employees participate in the LG&E and KU Team Incentive Award ("TIA"). The TIA focuses employee efforts on customer and business goals and rewards employees for achieving those goals. The TIA provides an opportunity for eligible employees to share in the added value they create through superior performance.

TIA AND BUSINESS STRATEGY

The company realizes the wealth that exists in the abilities of its people. The challenge is to become the best in our competitive market through each individual using his or her talents combined with other team members to make it happen. The TIA Plan plays a key role in assisting the company in focusing employees on customer and business goals as well as providing employees with a program that can increase their individual compensation.

The TIA was developed to motivate and direct employees toward the achievement of strategic goals. It also assists with attracting and retaining skilled personnel by providing competitive compensation commensurate with their talents, cooperation and contribution.

There are several basic TIA concepts:

- There is a focus on the cooperative spirit of all employees working together as a team.
- Risk-taking, embodied in initiative, fresh perspectives and innovative solutions, is encouraged and rewarded.
- The plan is designed to motivate and improve the individual performance of all employees.
- Incentive award levels vary depending on the employee's base salary, position and performance. The TIA represents "pay at risk." The relationship of the target awards to salary reflects that employees who have increasing responsibility for customer and business performance, as reflected in higher salaries, generally have a greater percentage of their compensation at risk.

With these concepts in mind, the TIA was designed:

- To promote the achievement of the company's objectives.
- To attract, motivate and retain employees.

TIA PLAN

Key elements of the TIA are as follows:

1. Participants include all active full-time and regular, part-time salaried employees, IBEW 2100 employees and KU hourly and bargaining unit employees.

2. All TIA participants have Target Awards based on the following:

Target Award Participation

Non-Exempt, BU & Hourly	6% of annual earnings
Exempt Individual Contributors	9% of base salary
Managers	14% of base salary
Senior Managers	25% of base salary

3. Performance objectives are established annually to support the customer and business strategies. The size of the awards depend upon the degree to which these objectives are achieved.

4. Exempt employees with salary changes during the year will have their awards calculated in accordance with the amount of time they work under each respective base salary.

5. Total annual earnings, including overtime, are used in calculating the earned awards for all regular non-exempt, BU and hourly full- and part-time employees. Prior TIA awards are excluded from total annual earnings to calculate earned awards.

6. Earned TIA Awards will be paid in cash within 90 days of the completion of the calendar-based annual performance period.

7. Compensation from the TIA is included in calculating benefits under the Company's Retirement (except for the KU Retirement Plan) and 401(k) Savings Plan.

8. This plan in no way creates a contract of employment for any duration. The company has full and final discretion with respect to the interpretation and application of this plan. The Company reserves the right to modify or terminate this plan in its sole discretion. This plan document supersedes any prior plan document relating to the TIA.

ELIGIBILITY

All active, regular full- and part-time salaried employees, IBEW 2100 employees and KU hourly and bargaining unit employees, who have at least one month continuous service and are on the payroll on December 31 of the performance year, are eligible for a TIA.

Employees who become disabled, die or retire during the performance year will be eligible for a prorated award.

Retirement, for the purpose of this plan, means that the employee is at least age 55 with 10 or more years of service. For those hired prior to 1/1/06, retirement means that the employee is eligible to retire under the terms of a company sponsored retirement plan.

Disability, for purpose of this plan, means that the employee is eligible for the receipt of benefits under the Long Term Disability Plan.

Upon an employee's death any prorated award shall be paid at the time such awards are payable under this plan to the employee's estate, or if the estate is closed at the time the award is payable to the person or persons in the first of the following classes of successive preference beneficiaries then surviving: the employee's surviving spouse, children, parents, brothers and sisters, executors and administrators.

Employees who join the company during the performance year, who have at least one month continuous service, and are on the payroll on December 31 will also be eligible for a prorated award. Employees incurring unpaid work days during the performance year may experience a proportionate reduction in their TIA.

INDIVIDUAL PERFORMANCE OBJECTIVES

The individual performance objective links individual performance to the TIA award. The individual performance objective can be combined with performance objectives for small teams as well as with key objectives from the Performance Excellence Process. Individual performance objectives should align with, and support, strategic customer and business goals to drive performance.

TIA COMMUNICATION

TIA performance results for customer, business and operational performance measures are communicated through the Company's internal communications to provide information concerning performance. Final TIA performance results are approved following the completion of the performance period and are communicated through the Company's internal communications.

CONCLUSION

The Team Incentive Award Plan is designed to strengthen the connection between pay and performance. It will direct a portion of total pay to awards based on customer, business, operational and individual achievements. The TIA focuses eligible employees' attention on the company's business goals.

TIA FORMULA

The TIA calculation formula is shown below, along with an example of a potential award. In this example, note the participant's salary is $40,000 and the target award is 9%.

TIA CALCULATION

Step 1: Target Award % x Annual Base Pay Earnings = Target Award

Step 2: Target Award x Corporate Safety Weighting x Performance % = Corporate Safety Award

Step 3: Target Award x Customer Satisfaction Weighting x Performance % = Customer Satisfaction Award

Step 4: Target Award x Cost Control Weighting x Performance % = Cost Control Award

Step 5: Target Award x Customer Reliability Weighting x Perfomance % = Customer Reliability Award

Step 6: Target Award x Individual or Team Weighting x Perfomance % = Individual or Team Award

Step 7: Corporate Safety Award + Customer Satisfaction Award + Cost Control Award
+ Customer Reliability Award + Individual or Team Award = Total TIA Award

TIA CALCULATION EXAMPLE

Annual Base Pay Earnings = $40,000
Target Award Percent = 9%
Corporate Safety Performance % = 105%
Customer Satisfaction Performance % = 110%
Cost Control Performance % = 100%
Customer Reliability Performance = 110%
Individual or Team Performance % = 105%

Step 1: 9% x $40,000 = $3,600 Total Award

Step 2: $3,600 x 15% x 105% = $567 Corporate Safety Award

Step 3: $3,600 x 15% x 110% = $594 Customer Satisfaction Award

Step 4: $3,600 x 15% x 100% = $540 Cost Control Award

Step 5: $3,600 x 15% x 110% = $594 Customer Reliability Award

Step 6: $3,600 x 40% x 105% = $1,512 Individual or Team Award

Step 7: $567 + $594 + $540 + $594 + 1,512 = $3,807 Total TIA Award

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	**)**	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	**)**	**CASE NO. 2020-00350**

TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

TABLE OF CONTENTS

I. BACKGROUND

Q. Please state your name, position and business address.

A. My name is Daniel K. Arbough. I am the Treasurer for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky. A statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes. I have testified in numerous proceedings before the Commission for many years. Most recently, I testified at the evidentiary hearing in KU's and LG&E's 2020 environmental surcharge cases.[1]

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (1) describe the business and planning process used in preparing the Companies' base and forecasted test periods; (2) present KU's and LG&E's capital structures; (3) describe KU's and LG&E's cost of debt, debt issuances since the last rate case, and forecasted debt issuances; and (4) support several filing requirements.

Q. Have your duties as Treasurer changed since the Companies' last rate cases?

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[1] *Electronic Application of Kentucky Utilities Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060, Hearing (Ky. PSC Sep. 10, 2020); *Electronic Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge*, Case No. 2020-00061, Hearing (Ky. PSC Sep. 10, 2020).

A. No, they have not. I continue to have responsibility for cash management, corporate finance, credit risk management, insurance, pension fund management oversight, and overseeing the Companies' forecasting and business planning processes, which is central to the development of the forecasted test period in these cases.

II. BUSINESS PLANNING PROCESS RESULTING IN THE FORECASTED TEST PERIOD

Q. What is the forecasted test period the Companies have used to support their requested increase in revenues in these cases?

A. The forecasted test period begins July 1, 2021, and ends June 30, 2022. The information and projections in the forecasted test period are the result of the Companies' annual business planning process.

Q. Please describe the business planning processes the Companies utilized in preparing the forecasted test period in these cases.

A. KU's and LG&E's business planning processes remain very similar to those I explained in my direct testimony in Case Nos. 2018-00294 and 2018-00295, which were the Companies' most recent rate cases. Consistent with their well-established business practices, the Companies prepare a five-year business plan each year that contains projected income statements, cash flow statements, and balance sheets. KU's and LG&E's budget is described in the first year of the five-year plan.[2] Preparing the five-year plan involves significant effort, which includes the use of econometric models, variables, assumptions, and changes in activity levels. All segments of the Companies participate, with many personnel contributing to the effort. In addition to my

[2] Certain filing requirements that support the Companies' applications reflect the full increase in revenues and contain no assumptions regarding the possible results of these cases.

testimony, a detailed description of these tools and how they are used are set forth in Filing Requirement Schedule 807 KAR 5:001 Section 16(7)(c) at Tab 16 of each application, as well as in the testimony of David S. Sinclair. The testimony of Lonnie E. Bellar also discusses assumptions.

Attached as Exhibit DKA-1 is a visual depiction of the planning process, and Exhibit DKA-2 contains a list of components from KU's and LG&E's income statement, balance sheet, and cash flow statement, the basis to derive each item, and the software system employed to arrive at each item.

Q. Have KU and LG&E each prepared a list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of their Applications as required by 807 KAR 5:001 Section 16(7)(t)?

A. Yes. This information is located at Tab 50 of each Company's application, and lists the software, programs, and models used in each utility's financial planning process and to develop the fully forecasted test period in this case.

Q. What are the two computer programs the Companies primarily utilize in their business planning process?

A. The two programs are UIPlanner and PowerPlan. The Companies are able to extract and import data from the two programs, which aids in the efficiency and continuity of business planning and forecasting. The Companies utilize UIPlanner's financial planning software, which is used by 21 of the largest 25 investor owned utilities in the United States, to consolidate data from several systems and generate projected financial statements for planning purposes. The Companies utilized UIPlanner in their 2014, 2016, and 2018 rate cases, as well.

Similarly, PowerPlan is a leading utility software used by nine out of ten North American investor owned utilities that allows the Companies to robustly manage their expenses and assets. KU and LG&E use the software to budget and track actuals for O&M, capital expenditures, taxes, and lease costs.

Q. Please explain the steps involved in KU's and LG&E's business planning process that led to the forecast in these cases.

A. In June of this year, KU and LG&E finalized their workforce plans and loaded the labor forecast into PowerPlan. Once complete, the corporate burdens (i.e., payroll taxes and worker's compensation) for employee benefits were calculated and entered into PowerPlan. Next, the electric and gas sales and commodity price forecasts were completed and loaded into UIPlanner. At this point, the capital plan was prepared, reviewed, and entered into PowerPlan.

Then the Generation forecast was completed, reviewed, extracted, and uploaded into UIPlanner. Next, Operations and Maintenance, Costs of Sales, and Other expense budgets were completed, reviewed, and loaded into PowerPlan. The PowerPlan data was then extracted and imported into UIPlanner. Once complete, Business Plan presentations were conducted for each line of business, reviews were performed, and necessary changes made. At this point, other revenue calculations, depreciation, financing, and tax calculations were made in UIPlanner.

Next, the comprehensive Business Plan was reviewed with KU and LG&E senior officers and changes were made to the plan based on their review. In the final steps, the Business Plan was submitted to PPL management for inclusion in the PPL consolidated financial projections, and ultimately will be reviewed and approved by the LKE Board and the PPL Board Finance Committee.

Q. Please explain how the labor forecasts that you mentioned are developed.

A. KU's and LG&E's Human Resources Department works closely with each business segment to determine future personnel needs, and determine planning assumptions for existing employees' development, retention, and anticipated staffing changes, including retirements. During this process, open positions and anticipated needs are analyzed. As discussed in Gregory J. Meiman's testimony, the Companies utilize annual benchmarking studies to determine salaries for new hires.

Information and data regarding KU's and LG&E's current workforce is housed in PeopleSoft, which is a computer software program the Companies use for many of their human resources functions. Information regarding wages, vacation hours, personal days, and sick time is extracted from PeopleSoft and imported into PowerPlan. KU and LG&E adjust the data based on expected changes in the workforce, union contracts, retirements, and pay adjustments based on the benchmarking surveys discussed above. Estimates are calculated for the amount of time each business segment will spend working each month on capital projects. Labor costs are split between capital, and operating and maintenance expense based on these estimates.

Q. How do the Companies determine the capital projects that are included in the business plan and in the forecasted test period in these cases?

A. Each line of business prepares a comprehensive list of capital projects that includes the expected investment over time, when construction would begin, and the expected in-service date. The Resource Allocation Committee ("RAC") is comprised of leaders from across the Companies and ensures that the capital budgets are prepared based on the needs of the business and our customers. Under the supervision of the RAC, changes in the five-year capital plan must be based on new facts and circumstances that are supportable based on the need for and cost effectiveness of the impacted projects.

Q. Can you provide an overview of how the electric sales, generation, and off-system sales forecasts are developed?

A. Yes. The Companies develop their electric sales, generation, and off-system sales forecasts through the business processes described in the Companies' integrated resource plans and certificate of public convenience and necessity cases filed with the Commission. Additionally, Mr. Sinclair's testimony provides a more thorough description of the assumptions, software, and methodology utilized in developing these forecasts.

Q. Please explain how operation and maintenance expenses are developed through business planning and for inclusion in the forecasted test period in these cases.

A. For many years, KU and LG&E have budgeted their operation and maintenance expenses through a "bottom-up" approach that begins with each line of business. The Companies used the same "bottom-up" approach to prepare the operation and maintenance budgets for this case. The expenses are budgeted to the corresponding Federal Energy Regulatory Commission ("FERC") account. These costs, along with labor, capital, and other costs, are thoroughly reviewed by various levels of management and presented to and approved by the Companies' senior officers. A copy of the current year's budget presentations is included at Tab 16 of KU's and LG&E's applications.

Q. Was this business planning process used to develop the fully forecasted test period ending June 30, 2022, for KU's and LG&E's applications?

A. Yes. The fully forecasted test period supporting these rate applications was developed through the Companies' business process described above under my supervision and direction subject to Mr. Blake's oversight.

Q. Did the Companies include certain assumptions concerning the cost of capital when developing the forecasted test period for these cases?

A. Yes, KU and LG&E included assumptions concerning their capital structures, cost of equity, and cost of debt in developing the forecasted test period supporting the rate applications in this case. Assumptions that are based on the forecasted cost of equity are set forth in Adrien M. McKenzie's testimony.

III. CAPITAL STRUCTURE

Q. Please explain the Companies' capital structures.

A. The Companies are firmly committed to maintaining their financial strength. A significant indicator of any company's financial strength is its level of debt as compared to total capitalization. A utility is no exception. A lower proportion of debt signals that a company should have sufficient cash flow to meet its interest and other debt obligations when they are due. Also, maintaining a moderate level of existing debt affords a company greater flexibility to raise additional funds when needed. Cumulatively, this leads to higher credit ratings and lower interest costs.

The Companies maintain their capital structures in adherence with these bedrock principles. For the forecasted test period, KU has projected a debt-to-capitalization ratio of 46.9 percent.[3] This is consistent with KU's year-end ratios since 2010, which have stayed within 45.9 to 48.2 percent.[4]

Likewise, for the forecasted test period, LG&E has projected a debt-to-capitalization ratio of 46.9 percent.[5] This is consistent with LG&E's year-end ratios since 2010, which have stayed within 43.8 to 48.4 percent.[6] Maintaining these ratios is consistent with KU's and LG&E's long-standing targeted bond rating of "A."

Q. Please explain how Moody's evaluates a utility's capital structure.

A. Moody's approach is explained in its *Rating Methodology, Regulated Electric and Gas Utilities*, dated June 23, 2017, a copy of which is attached to my testimony as Exhibit DKA-3. Moody's considers four factors: (1) regulatory framework; (2) ability to recover costs and earn returns; (3) diversification; and (4) financial strength.

The financial metrics Moody's evaluates in assigning a credit rating include the entity's debt-to-capitalization ratio. Moody's states, "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 credit facilities or other financing agreements."[7]

KU and LG&E aim for an "A" rating from Moody's. An "A" rating is consistent with a debt-to-capitalization ratio of 35 percent to 45 percent as calculated by Moody's. Moody's, like other credit rating agencies, makes several adjustments in computing a company's debt and capitalization. For example, long-term obligations

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[3] Schedule J-1 at 1.
[4] These quarter-end ratios exclude purchase accounting adjustments reflected in federal GAAP filings.
[5] Schedule J-1 at 1.
[6] These quarter-end ratios exclude purchase accounting adjustments reflected in federal GAAP filings.
[7] Moody's *Rating Methodology, Regulated Electric and Gas Utilities*, June 23, 2017 at 21.

under pensions and leases are considered "debt" obligations, and deferred taxes are included as part of capitalization. Taking into account Moody's adjustments, KU's debt-to-capitalization ratio at the end of the base period is 36.8 percent; for the end of the forecasted test period it is 37.8 percent, both within Moody's range for an "A" rating. LG&E's debt-to-capitalization ratio for the base period is also within the "A" range, as it is 37.6 percent at the end of the base period and 38.3 percent at the end of the forecasted test period.

Moody's includes deferred taxes in its definition of capitalization, and the passage of bonus depreciation has caused a significant increase in the Companies' deferred tax balances. KU's deferred tax balance is approximately $828 million, and LG&E's is approximately $712 million as of September 30, 2020. The magnitude of the deferred taxes is the cause for the debt/total capitalization ratio being slightly below the mid-point of the range. The Companies cannot simply incorporate deferred taxes into its target ratios because other agencies do not include deferred taxes in their ratios, which is discussed below.

Q. Please explain how other rating agencies evaluate capital structures.

A. Like Moody's, Standard & Poor's ("S&P") evaluates capital structure as part of its credit rating process. I have attached to my testimony as Exhibit DKA-4 the general criteria and methodology S&P uses for corporate industrial borrowers and utilities. S&P's methodology assigns values to the following: Country Risk, Industry Risk, and Competitive Position, each of which is considered in establishing a "Business Risk Profile." The "Business Risk Profile" is considered with a company's "Financial Risk Profile," which is based on a company's cash flow as compared to its obligations. I have also attached to my testimony as Exhibit DKA-5 the S&P *Key Credit Factors for the Regulated Utilities Industry*, dated November 19, 2013 (as republished July 22, 2020, to make nonmaterial changes). The article in Exhibit DKA-5 explains how S&P modifies the general criteria methodology contained in Exhibit DKA-4 for utilities.

The result is adjusted by "modifiers" that include capital structure and beyond the standard cash flow adequacy and leverage analysis (such as debt maturities, interest-rate volatility, and currency issues). An additional modifier is corporate financial policy, which is S&P's positive or negative assessment of the company's management. Another S&P modifier is liquidity, which is a company's ability to meet its obligations in the event of an earnings decline, or other low probability negative events.

A company's debt/(debt + equity) ratio affects both its Financial Risk Profile regarding its cash flow, as well as the Capital Structure and Liquidity modifiers. Although S&P's methodology does not establish a direct correlation between a certain debt/(debt + equity) ratio and a particular rating, a company's capital structure has a direct impact on the requirements to meet S&P's rating guidelines. Unlike Moody's, S&P does not include deferred taxes in its ratio. Using S&P's adjustments, KU's debt/(debt + equity) ratio is 43.2 percent for the base period and 43.8 percent for the forecasted test period. LG&E's is 44.6 percent for the base period and 45.2 percent for the forecasted test period. Both KU's and LG&E's current capital structures retain the Financial Risk Profile in the "Intermediate" category (based on S&P's low volatility table) which, when combined with its "Excellent" Business Risk Profile is consistent with the Companies' target "A" rating.

Q. Please explain why credit rating agencies such as Moody's and S&P adjust a utility's debt balance when determining the capital structure.

A. Credit rating agencies view certain obligations, such as leases, pensions, and post-retirement benefit obligations, as fixed obligations that are equivalent to debt. The Companies accordingly makes corresponding adjustments when calculating the debt in their target capital structure.

IV. CREDIT RATINGS

Q. What are the Companies' current credit ratings?

A. Filing requirement 807 KAR 5:001 Section 16(8)(k) at Tab 64 in KU's and LG&E's applications show the current credit ratings for KU and LG&E. Presently, Moody's rating is A3 (with the first mortgage bonds rated A1), and S&P's rating is A- (with first mortgage bonds rated A). These strong credit ratings enable KU and LG&E to continue to raise debt capital at very reasonable costs.

Q. Have there been any changes to the Companies' credit ratings since Case Nos. 2018-00294 and 2018-00295, which were their last rate cases?

A. No, there have not.

Q. Do KU and LG&E have sufficient access to short term capital?

A. Yes. Several months ago, the Commission authorized KU and LG&E to incur additional debt due, in large part, to the impact of COVID-19 on the Companies.[8] KU has authority to issue up to $650 million in short-term debt,[9] and maintains a $400

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[8] *Electronic Application of Kentucky Utilities Company for Issuance of Indebtedness*, Case No. 2020-00109, Order (Ky. PSC June 16, 2020); *Electronic Application of Louisville Gas and Electric Company for an Order Authorizing the Issuance of Indebtedness*, Case No. 2020-00110, Order (Ky. PSC May 26, 2020).
[9] Case No. 2020-00109, Order (Ky. PSC June 16, 2020).

million line of credit. In addition, KU maintains a commercial paper program of $350 million. LG&E has authority from the FERC to issue up to $750 million in short-term debt,[10] and maintains a $500 million line of credit. LG&E likewise maintains a commercial paper program of $350 million.

V. RETURN ON COMMON EQUITY

Q. Have you reviewed the testimony of Adrien M. McKenzie of FINCAP, Inc. regarding return on common equity?

A. Yes, I have.

Q. Do you believe Mr. McKenzie's proposed return on common equity is reasonable?

A. Yes, I do. I have reviewed his analyses that support his recommendation and find Mr. McKenzie's proposed return on common equity of 10.0 percent to be fair and reasonable.

Q. Are the Companies also requesting Mr. McKenzie's proposed return on common equity be applied to the rate base remaining in the Environmental Cost Recovery ("ECR") mechanism after this case?

A. Yes.

VI. COST OF DEBT AND DEBT ISSUANCE

Q. Do the Companies' cost of debt compare favorably to other utility companies?

A. Yes, it does. Since 2007, the Companies have closely monitored their cost of debt in comparison to a peer group of other utility companies on a quarterly basis. KU's and LG&E's cost of debt has consistently ranked favorably during this nearly 14-year period. As shown on Exhibit DKA-6, KU's cost of debt (combined taxable and tax-

[10] Case No. 2020-00110, Order (Ky. PSC May 26, 2020).

exempt debt) is within the middle third of the twenty-five member group for the twelve months ending June 30, 2020. LG&E's cost of debt is also within the middle third of the debt costs of the group. This comparison further demonstrates that the Companies' cost of debt is reasonable.

Q. What debt issuance activities have occurred since the filing of the last rate case in September 2018?

A. The Companies were able to take advantage of historically low interest rates in remarketing many existing bonds and issuing new bonds. KU had the following debt issuance activities since September 2018:

Date	Bond	Activity	Amount
June 2020	First Mortgage Bond	Issued	$500 million
August 2019	Carroll County 2004 Series A Bond	Converted from variable rate mode to fixed rate	$50 million
August 2019	Carroll County 2006 Series B Bond	Converted from variable rate mode to fixed rate	$54 million
August 2019	Carroll County 2008 Series A Bond	Converted from variable rate mode to fixed rate	$77.947 million
August 2019	Carroll County 2016 Series A Bond	Converted from variable rate mode to fixed rate	$96 million
August 2019	Mercer County 2000 Series A Bond	Converted from variable rate mode to fixed rate	$12.9 million
April 2019	First Mortgage Bond	Issued (reopened 2015 issuance)	$300 million
September 2018	Carroll County Series A Bond	Refinanced	$17.875 million

LG&E had the following debt issuance activities since September 2018:

Date	Bond	Activity	Amount
September 2020	Trimble County 2016 Series A Bond	Converted from variable rate mode to fixed rate	$125 million
September 2020	Louisville Metro 2001 Series A Bond	Converted from variable rate mode to fixed rate	$22.5 million
September 2019	Louisville Metro 2005 Series A Bond	Remarketed	$40 million
April 2019	First Mortgage Bond	Issued	$400 million

April 2019	Louisville Metro 2003 Series A Bond	Remarketed	$128 million

Additionally, in March 2019, KU and LG&E each extended the terms of their revolving credit facilities pursuant to the authority granted by the Commission in Case Nos. 2018-00153 and 2018-00335.

Q. What debt issuance activities do KU and LG&E expect between now and the end of the forecasted test period?

A. KU and LG&E expect to issue new long-term debt of $200 million and $300 million, respectively between now and the end of the forecasted test period. In addition, KU and LG&E each have tax-exempt bonds which will be remarketed between now and the end of test period to reset the interest rates. The KU bonds that will reset interest rates on June 1, 2021 are the $77.9 million Carroll County 2008 Series A and the $54 million Carroll County 2006 Series B bonds. The LG&E tax-exempt bonds that will have the interest rates reset are the $128 million Louisville Metro 2003 Series A to be reset on April 1, 2021, the $35 million Jefferson County 2001 Series B and the $35 million Trimble County 2001 Series B to be reset on May 3, 2021, the $35.2 million Louisville Metro 2007 Series B and the $31 million Louisville Metro 2007 Series A to be reset on June 1, 2021, and the $27.5 million Trimble County 2001 Series A to be reset on September 1, 2021.

VII. SCHEDULES REQUIRED BY 807 KAR 5:001 SECTION 16

Q. Are you sponsoring certain schedules required by the Commission's regulation 807 KAR 5:001 Section 16?

A. Yes, I am sponsoring (or co-sponsoring) the schedules required by 807 KAR 5:001 Section 16 for both KU's and LG&E's applications:

Section 16(7)(b)	Most recent capital construction budget containing at minimum a 3-year forecast of construction expenditures
Section 16(7)(c)	Complete description, which may be written testimony form, of all factor uses to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained and properly supported
Section 16(7)(d)	Utility's annual and monthly budget for twelve (12) months preceding filing date, base period, and forecasted period
Section 16(7)(f)	For each major construction project which constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast the following information shall be filed: 1. The date the project was started or estimated starting date; 2. The estimated completion date; 3. The total estimated cost of construction by year exclusive and inclusive of allowance for funds used during construction ("AFUDC") or interest during construction credit; and 4. The most recent available total costs incurred exclusive and inclusive of AFUDC or interest during construction credit
Section 16(7)(g)	For all construction projects which constitute less than five (5) percent of the annual construction budget within the three (3) year forecast, the utility shall file an aggregate of the information requested in paragraph (f)3 and 4 of this subsection
Section 16(7)(h)(1-4), (9)-(12)	A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share); 2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return *** 9. Employee level; 10. Labor cost changes; 11. Capital structure requirements;

	12. Rate base;
Section 16(7)(j)	The prospectuses of the most recent stock or bond offerings
Section 16(7)(n)	The latest twelve (12) months of the monthly managerial reports providing financial results of operations in comparison to the forecast
Section 16(7)(o)	Complete monthly budget variance reports, with narrative explanations, for the twelve (12) months immediately prior to the base period, each month of the base period, and any subsequent months, as they become available
Section 16(7)(t)	A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; the specifications for the computer hardware and the operating system required to run the program
Section 16(8)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period
Section 16(8)(j)	A cost of capital summary for both the base period and forecasted period with supporting schedules providing details on each component of the capital structure
Section 16(8)(k)	Comparative financial data and earnings measures for the ten (10) most recent calendar years, the base period, and the forecast period

A. Cost of Capital Summary

Q. Has KU and LG&E each prepared a cost of capital summary for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(j)?

A. Yes. This information ("Schedule J") is located at Tab 63 to the applications. Schedule J consists of five schedules:

- J-1 Cost of Capital Summary
- J-1.1/J-1.2 Average Forecasted Period Capital Structure

- J-2 Embedded Cost of Short-Term Debt
- J-3 Embedded Cost of Long-Term Debt
- B-1.1 Jurisdictional Rate Base for Capital Allocation

Schedules J-2 and J-3, and Supporting Schedule B-1.1 provide inputs to the calculations shown on Schedules J-1 and J-1.1/J-1.2. I sponsor each of the schedules, except for B-1.1, which is sponsored by Mr. Garrett.

Q. Please describe Schedule J-1.

A. In KU's application, Schedule J-1 shows the calculation of its adjusted capitalization, as well as the weighted average cost of capital, as of the end of the base and forecasted test periods.

For LG&E, Schedule J-1 shows the calculation of its adjusted capitalization for electric and gas operations, as well as the weighted average cost of capital, as of the end of the base and forecasted test periods for its electric and gas operations.

Q. Please describe Schedule J-1.1/J-1.2 filed to support KU's application.

A. As 807 KAR 5:001 Section 16(6)(c) requires, Schedule J-1.1/J-1.2 shows the calculation of KU's 13-month-average adjusted capitalization, as well as the weighted average cost of capital, KU used to determine the net operating income found reasonable on Schedule A. As indicated on Schedule J-1.1/J-1.2, the requested rate of return on capitalization is 7.21 percent, based on the proposed 10.0 percent return on common equity proposed by KU, which is the return on common equity recommended by Mr. McKenzie. Page 1 provides this calculation, while page 2 details the "Adjustment Amount" included in Column D of page 1 and page 3 details the "Jurisdictional Adjustments" included in Column H of page 1.

The adjustments on page 2 of this schedule remove KU's equity investment in Electric Energy Inc., Ohio Valley Electric Corporation, other net non-utility investments, adjust deferred income tax amounts as discussed in Mr. Chris Garrett's testimony, and Advanced Metering Infrastructure ("AMI") related amounts. With the exception of the deferred tax and AMI amounts, the adjustments on page 2 are consistent with the adjustments approved in the Commission's Orders in Case Nos. 2009-00548 and 2003-00434, and as proposed by KU in Case Nos. 2018-00294, 2016-00370, 2014-00371, 2012-00221, and 2008-00251, which were resolved by settlements approved by the Commission.

The adjustments on page 3 of this schedule remove KU's ECR Surcharge, the Demand Side Management ("DSM") cost-recovery mechanism rate base amounts, and AMI rate base amounts from capitalization to be considered in this proceeding. Removing ECR and DSM rate base from KU's capitalization is necessary because KU recovers its ECR and DSM capital investments, and a return on those investments, through the environmental surcharge and DSM cost-recovery mechanisms. As discussed further in the testimony of Robert M. Conroy, KU proposes to eliminate certain ECR projects from their mechanism and recover the projects through base rates. KU therefore has included in capitalization the ECR projects that KU proposes to recover through base rates. And as discussed in Mr. Blake's testimony, the AMI investment is excluded from the revenue requirement calculations in these cases.

Column F on page 1 of this schedule contains the rate-base allocation factor to remove from KU's total utility capitalization all non-Kentucky-jurisdictional capital. The rate-base-allocation factor is calculated on Supporting Schedule B-1.1.

Column J shows each capital component's percentage of total capitalization, which is calculated by dividing the individual capital component's amount shown in Column I by the "Total Capital" shown at the bottom of Column I. Column K shows the cost rate for each capital component: short-term debt from Schedule J-2, long- term debt from Schedule J-3, and the return on common equity I discussed above. Finally, Column L multiplies capitalization percentages in Column J by the cost rates in Column K to obtain the 13-month-average weighted cost of each capital component. The total weighted capital cost, 7.21 percent, appears in Line 4 of Schedule A.

Q. Please describe Schedule J-1.1/J-1.2 filed to support LG&E's application.

A. Schedule J-1.1/J-1.2 shows the calculation of LG&E's 13-month-average adjusted capitalization for electric and gas operations, as well as the weighted average cost of capital, LG&E used to determine the net operating income found reasonable on Schedule A. As indicated on Schedule J-1.1/J-1.2, the requested rate of return on electric and gas capitalization is 7.17 percent, based on the proposed 10.0 percent return on common equity proposed by LG&E, which is the return on common equity recommended by Mr. McKenzie. Pages 1 and 2 provide this calculation for the electric and gas operations, respectively. Pages 3 and 4 detail the "Adjustment Amount" reflected in Column F of Pages 1 and 2.

The adjustments on pages 3 and 4 of this Schedule at Column E remove the ECR rate base from the electric operations' capitalization and the Gas Line Tracker ("GLT") rate base from the gas operations' capitalization. The adjustments on pages 3 and 4 of this Schedule at Column F remove the DSM rate base amounts from both the electric and gas operations' capitalization to be considered in this proceeding.

Removing ECR, GLT, and DSM rate base from the electric and gas operations' capitalization is necessary because LG&E recovers its ECR, GLT, and DSM capital investments and a return on those investments through the ECR, GLT and DSM cost-recovery mechanisms. As discussed further in Mr. Conroy's testimony, LG&E proposes to eliminate certain ECR and GLT projects from their respective mechanisms and recover the projects through base rates. LG&E therefore has included in capitalization the ECR and GLT projects that LG&E proposes to recover through base rates.

The adjustments on Pages 3 and 4 of this Schedule at Columns G through J remove from LG&E's capitalization the 25 percent portion of Trimble County Unit No. 1 inventories that represent Illinois Municipal Electric Agency's ("IMEA") and Indiana Municipal Power Association's ("IMPA") portions of these assets, LG&E's equity investment in Ohio Valley Electric Corporation and other investments, and add the Job Development Investment Tax Credit, the Qualifying Advanced Coal Project Program Investment Tax Credit, and the Solar Investment Tax Credit, consistent with the adjustments the Commission approved in Case Nos. 2009-00549 and 2003-00433, and as proposed by LG&E in Case Nos. 2018-00294, 2016-00371, 2014-00372, 2012-00222, and 2008-00252, which were resolved by a settlement approved by the Commission. The Job Development Investment Tax Credit is the only adjustment in Columns G through J that applies to gas operations' capitalization and is included in Column H on page 4.

The adjustments in column K of page 3 and H of page 4 adjust the deferred income taxes as discussed in the testimony of Mr. Chris Garrett. The adjustments in column L of page 3 and I of page 4 remove AMI from the rate base. Again, as discussed in Mr. Blake's testimony, the AMI investment is excluded from the revenue requirement calculations in these cases.

Column D on pages 1 and 2 of this schedule reflect the rate base allocation factor to allocate the 13-month average between electric and gas operations. Column H shows each capital component's percentage of total capitalization, which is calculated by dividing the individual capital component's amount shown in Column G by the "Total Capital" shown at the bottom of Column G. Column I shows the cost rate for each capital component: short-term debt from Schedule J-2, long-term debt from Schedule J-3, and the return on common equity I discussed above. Finally, Column J multiplies capitalization percentages in Column H by the cost rates in Column I to obtain the 13-month-average weighted cost of each capital component. This weighted capital cost, 7.17 percent, is shown in Column J and is used on Line 4 of Schedule A to calculate the Company's Required Operating Income for the forecasted period.

Q. Please describe Schedule J-2 in KU's and LG&E's applications.

A. Schedule J-2 consists of three pages, each of which provides the short-term debt amounts, corresponding interest rates, and weighted cost of short-term debt for the relevant time period. The first page provides the short-term debt information as of the end of the base period, February 28, 2021. The second page provides the short-term debt information as of the end of the forecasted test period, June 30, 2022. The third page provides the 13-month-average short-term debt information for the forecasted test period.

Q. Please explain how KU's and LG&E's cost of short-term debt was calculated on Schedule J-2.

A. Short-term debt costs are based on interest expense from commercial paper issuances. For future periods, the interest rate is based on forward LIBOR curves. At the end of the base period, KU's rate is projected to be 0.483 percent, and for the forecasted period the 13-month average rate is calculated to be 0.459 percent. LG&E's rates at the end of the base period and the forecasted 13-month average rate are 0.483 percent and 0.46 percent, respectively. The base period calculation of short-term debt costs are shown on page 1 of Filing Schedule J-2 while the 13-month average is calculated on page 3 of Schedule J-2 as required by 807 KAR 5:001 Section 16(8)(j). KU and LG&E expect to provide updates on the cost of short-term debt as the cases develop.

Q. Please describe Schedule J-3 in KU's and LG&E's applications.

A. Schedule J-3 consists of three pages, each of which provides the long-term debt information necessary to calculate the embedded cost of long-term debt for the relevant time period, which is shown at the bottom right-hand corner of each page's data. The first page provides the long-term debt information as of the end of the base period, February 28, 2021. The second page provides the long-term debt information as of the end of the forecasted test period, June 30, 2022. The third page provides the 13-month-average long-term debt information for the forecasted test period.

Q. Please describe how KU's cost of long-term debt was calculated on Schedule J-3.

A. KU's weighted-average cost of long-term debt at the end of the base period is projected to be 4.13 percent. Consistent with prior rate cases, this includes all components of interest expense for each bond, including the interest paid to bondholders, amortization of bond issuance costs, amortization of losses on reacquired debt, amortization of debt discounts, amortization of credit facility costs, fees for credit enhancements such as bond insurance fees and letters of credit where applicable, and amortization of pre-issuance hedging gains or losses. The unamortized pre-issuance hedge losses shown on Schedule J-3 are accounted for as regulatory assets and pre-issuance hedge gains are accounted for as regulatory liabilities and the balances in both instances are amortized straight-line over the life of the corresponding bond to interest expense.

KU's weighted-average cost of long-term debt for the forecasted test period is calculated as 4.16 percent. The calculation of KU's cost of long-term debt is detailed on Filing Schedule J-3 required by 807 KAR 5:001, Section 16(8)(j).

Q. Please describe how LG&E's cost of long-term debt was calculated on Schedule J-3.

A. LG&E's weighted-average cost of long-term debt at the end of the base period is projected to be 4.15 percent. Consistent with prior rate cases, this includes all components of interest expense for each bond, including the interest paid to bondholders or bank, amortization of the debt issuance costs, amortization of losses on reacquired debt, amortization of debt discounts, amortization of credit facility costs, fees for credit enhancements such as bond insurance and letters of credit where applicable, interest paid on outstanding interest rate swap agreements, and amortization of pre-issuance hedging gains or losses. A regulatory asset has been recorded for the mark-to-market value of the outstanding interest rate swaps. This regulatory asset is amortized to interest expense as shown on Schedule J-3 in the amount of the monthly cash settlements and monthly fluctuations in the mark-to-market value are recorded to the regulatory asset balance. Additionally, the unamortized pre-issuance hedge losses shown on Schedule J-3 are accounted for as regulatory assets and pre-issuance hedge gains are accounted for as regulatory liabilities and the balances in both instances are amortized straight-line over the life of the corresponding bond to interest expense.

LG&E's weighted-average cost of long-term debt for the forecasted test period is calculated as 4.04 percent. The calculation of LG&E's cost of long-term debt is detailed on Filing schedule J-3 as required by 807 KAR 5:001, Section 16(8)(j).

Q. Does this conclude your testimony?

A. Yes, it does.

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 foregoing testimony, and that 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 November 2020.

Judy Schooler

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

July 11, 2022

APPENDIX A

Daniel K. Arbough
Treasurer
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4956

Previous Positions

E.ON U.S. LLC

Director, Corporate Finance and Treasurer	January 2001 – September 2007

LG&E Energy Corp.

Director, Corporate Finance	May 1998 – January 2001
Manager, Corporate Finance	August 1996 – May 1998

LG&E Power Inc.

Manager, Project Finance	June 1994 – August 1996

Conoco Inc., Houston, Texas

Corporate Finance, Project Finance, and Credit Management	June 1988 – May 1994

Boise Cascade Office Products, Denver, Colorado

Inventory Management	November 1983 – September 1987

Professional/Trade Memberships

National Association of Corporate Treasurers
Association for Financial Professionals
Financial Executives International

Education

Master of Business Administration – Finance – May 1988 – University of Denver
Bachelor of Science Business Administration – General Business – June 1983
University of Denver

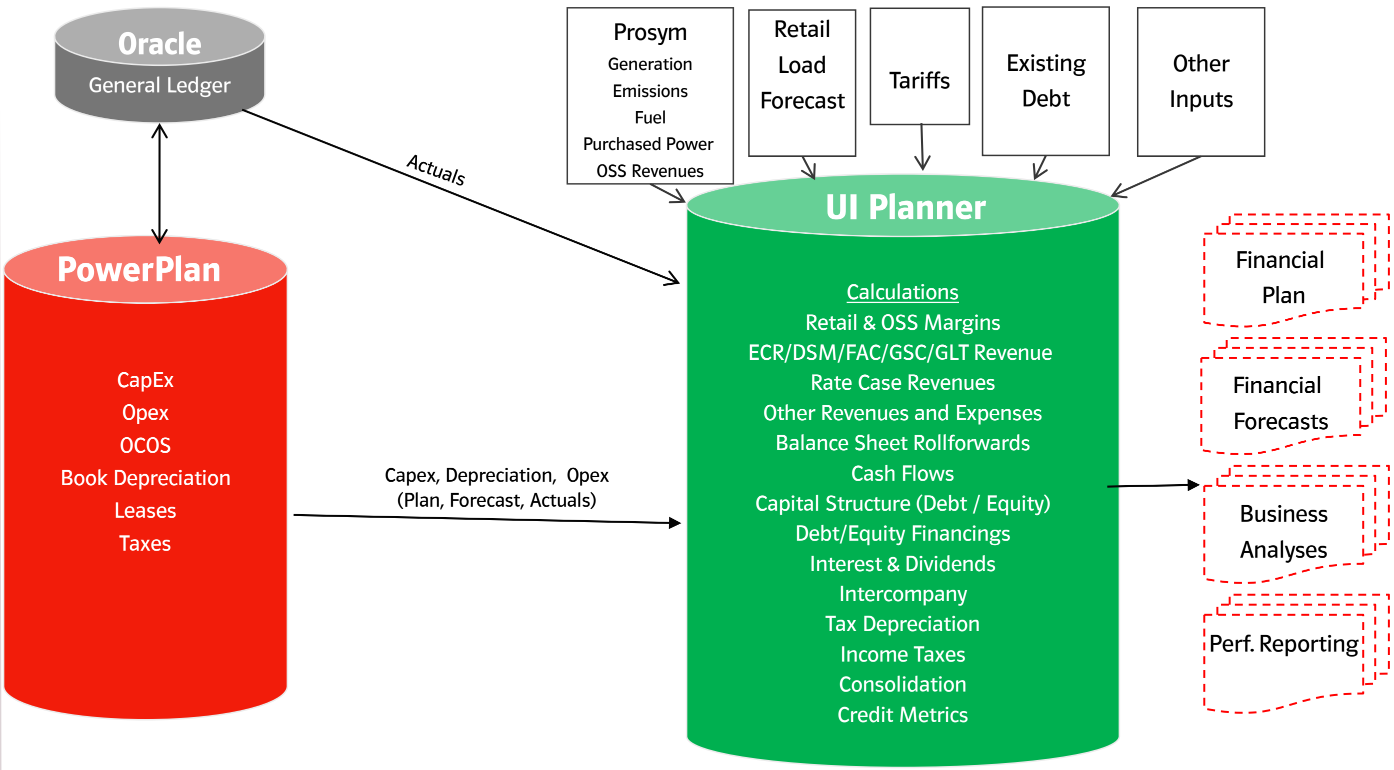
Civic Activities

Louisville and Jefferson County Metropolitan Sewer District – Board of Directors – April 2012 – current (currently Vice-Chair)
Leadership Louisville – Bingham Fellows – Class of 2012
National Center for Families Learning – Endowment Oversight Committee Member
Louisville Central Community Centers – Past President of Board of Directors

Exhibit DKA – 1

Visual depiction of the planning process

Financial Planning Software



LG&E KU
PPL companies

Exhibit DKA-2

Financial Summary Table

Income Statement

Line Item	***Basis to Derive***	***System Employed***
Gross Margin Components:		
Customer Revenue	Load Forecast x Approved Tariff	UIPlanner
Demand Charge Revenue	Load Forecast x Approved Tariff	UIPlanner
Energy Revenue	Load Forecast x Approved Tariff	UIPlanner
Base Fuel Revenue	Load Forecast x Approved Tariff	UIPlanner
FAC Revenue	Difference between recoverable Fuel + Purchased Power below and Base Fuel Revenue	UIPlanner
ECR Revenue	Revenue requirement calculated using the following: rate base rolled forward for identified ECR projects using capital spend and in service dates per PowerPlan and calculated deferred income taxes; jurisdictional factor computed within UIPlanner using KY retail/total revenue ratio; cost of capital computed within UIPlanner using weighted average cost of debt, authorized ROE and target capital structure	UIPlanner PowerPlan
DSM Revenue	Revenue requirement calculated in UIPlanner based on expenses, incentive percentage, capital and lost sales volumes per DSM filing with lost sales priced using current tariffs	UIPlanner
Gas Line Tracker Revenue	Revenue requirement calculated in UIPlanner using the following: rate base rolled forward for identified GLT projects using capital spend and in service dates per PowerPlan and calculated deferred income taxes; cost of capital computed within UIPlanner using weighted average cost of debt, authorized ROE and target capital structure	UIPlanner PowerPlan
Intercompany Sales	Based on generation and load forecast relative to market prices for each utility	Prosym
Off-System Sales	Based on generation and load forecast relative to market prices	Prosym
Transmission Revenue	Projected volumes based on trends and known changes x OATT approved rate Intercompany costs brought in via PowerPlan	Excel PowerPlan
Other Operating Revenue	Projected based on historical trends or current contracts (if any) as well as incorporating any tariff changes.	Excel
Fuel	Based on generation forecast and heat rates by plant x price curves which are a blend of contracted rates and market prices for unhedged positions	Prosym
Gas Supply	Gas load forecast priced out at contracted rates and market prices for open/indexed positions	Excel

Income Statement

Line Item	***Basis to Derive***	***System Employed***
Purchased Power	Projected in generation forecast model run using contracted capacity terms and market prices	Prosym
Other Cost of Sales	Existing contract/market prices for consumables applied to generation forecast by plant and usage rates for each plant	PowerPlan
Rate Mechanism Expenses	Projected O&M costs and depreciation by approved project	PowerPlan
Other Operating & Maintenance Expenses	Detailed "bottoms up" aggregation by department	PowerPlan
Taxes Other Than Income	Based on capital plan, classifications of property and property tax rates	Excel UIPlanner PowerPlan
Depreciation & Amortization	Based on capital plan, including property classifications and in service dates, and approved depreciation rates (Filed rates based on most recent depreciation study to be approved by the KPSC)	PowerPlan
Interest Expense	Product of existing debt (accounting for debt repayments) and interest rates as well as projected debt issuances at market rates, incorporating hedges and amortization of debt issuance costs	UIPlanner
Other Income (Expense)	Projected based on trends and known changes	Excel
Income Tax Provision	Based on earnings, calculated permanent and timing differences and current tax laws and positions	UIPlanner
Net Income	Sum of the Above	UIPlanner

Balance Sheet

Line Item	***Basis to Derive***	***System Employed***
Cash	Derived from cash flow statement for current year, projected balances are set at $5 million per utility.	UIPlanner
Accounts Receivable	Based on revenues and projected days of sales in receivables based on history and trends	UIPlanner
Fuels, Materials & Supplies	Fuel inventory roll forward maintained in UIPlanner based on target inventory levels, generation forecast per Prosym and contract/market prices	UIPlanner Prosym
Regulatory Assets/Liabilities	Rollforward maintained based on amortization periods, rate mechanism revenue calculations and other changes in expenses/payments as applicable	UIPlanner
Utility Plant	Rollforward maintained based on capital spend, in service and retirement dates, and depreciation	UIPlanner PowerPlan

Balance Sheet

Line Item	***Basis to Derive***	***System Employed***
Leases	Monthly balance sheet amounts are obtained via Excel from the PowerPlan Lease module and uploaded to UI.	Excel PowerPlan
Other Assets	Current levels only adjusted for known changes	
Accounts Payable	Function of capital and O&M spend, adjusted for some payment lag	UIPlanner
Accrued Interest	Calculated based on debt schedules	UIPlanner
Accrued Taxes	Calculated based on income tax expense calculations and payment schedules	UIPlanner
Deferred Income Taxes	Rollforward maintained based on book and tax depreciation using capital plan, current tax rates and book depreciation rates	UIPlanner PowerPlan
Accrued Pension Obligations	Based on projected expense and funding per actuarial study	UIPlanner
Other Liabilities	Current levels only adjusted for known changes	UIPlanner
Debt	Detail of existing debt supplemented with projected debt issuance and repayments	UIPlanner
Stockholder's Equity	Roll forward based on net income, dividends and equity contributions	UIPlanner

Cash Flow Statement

Line Item	***Basis to Derive***	***System Employed***
Cash From Operating Activities	Derived from income statement and balance sheet changes above	UIPlanner
Capital Expenditures	Per detailed capital plan by project, adjusted for cash payment timing	PowerPlan
Debt Issuance/Repayment	Net cash surplus (shortfall) applied to repayment (borrowing) of short-term debt until sufficient balance to issue long-term debt; other debt repayments based on existing debt terms; maintain target capital structure	UIPlanner
Dividends	Based on 65% payout ratio	UIPlanner
Equity Contributions	Projected as needed to maintain target capital structure based on other cash flow items	UIPlanner

Exhibit DKA-3

Moody's Investors Service

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

Table of Contents:

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

Summary

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

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

THIS RATING METHODOLOGY WAS UPDATED ON FEBRUARY 15, 2018. WE HAVE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34.

THIS RATING METHODOLOGY WAS UPDATED ON SEPTEMBER 27, 2017. WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

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

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

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

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

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

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

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

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

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

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4,5] 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. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

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

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

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

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

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

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

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

About this Rating Methodology

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

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

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

Factor / Sub-Factor Weighting - Regulated Utilities

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

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

2. Measurement or Estimation of Factors in the Grid

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

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

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

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

3. Mapping Factors to the Rating Categories

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

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

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

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

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

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

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

Grid-Indicated Rating

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

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

Grid-Indicated Rating

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

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

6. Appendices

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

Discussion of the Grid Factors

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

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

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

Factor 1: Regulatory Framework (25%)

Why It Matters

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

How We Assess Consistency and Predictability of Regulation for the Grid

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

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

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

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

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

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

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

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

Why It Matters

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

How We Assess Ability to Recover Costs and Earn Returns

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

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

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

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

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

How We Assess Sufficiency of Rates and Returns for the Grid

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

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

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

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

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

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

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

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

Factor 3: Diversification (10%)

Why It Matters

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

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

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

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

How We Assess Market Position for the Grid

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

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

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

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

How We Assess Generation and Fuel Diversity for the Grid

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

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

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

Factor 3: Diversification (10%)

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

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

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

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

Factor 4: Financial Strength (40%)

Why It Matters

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

How We Assess It for the Grid

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

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

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

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

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

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

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

CFO Pre-Working Capital / Debt

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

CFO Pre-Working Capital Minus Dividends / Debt

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

Debt/Capitalization

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

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

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

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

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

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

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

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

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[1310] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

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

How We Assess It

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

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

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

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

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

Strained liquidity at the HoldCo level

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

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

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

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

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

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

» Meaningful dividends to HoldCo from unlevered utility OpCos

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

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

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

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

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

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

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

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

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

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

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

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

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

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

Other Rating Considerations

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

Liquidity and Access to Capital Markets

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

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

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

Management Quality and Financial Policy

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

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

Size – Natural Disasters, Customer Concentration and Construction Risks

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

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

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

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

Diversified Operations at the Utility

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

Event Risk

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

Corporate Governance

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

Investment and Acquisition Strategy

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

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

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

Financial Controls

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

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

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

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

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based 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.

* 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	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
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	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.	

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

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

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

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

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

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

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

Factor 3: Diversification (10%)

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

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

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

Factor 4: Financial Strength

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

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

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

General Approach to a Utility Family

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

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[1614] 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.

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

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

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

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

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

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

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

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

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

Economic and Financial Market Conditions

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

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

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

Fuel Price Volatility and the Global Impact of Shale Gas

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

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

Distributed Generation Versus the Central Station Paradigm

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

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

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

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

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

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

Nuclear Issues

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

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

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited and its parent, Korea Electric Power Corporation, faced a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be shut down temporarily.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers," including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

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

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

Securitization

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

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

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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 follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

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

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

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

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

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

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

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

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

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

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

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

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

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

Additional considerations for PPAs

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

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

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

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

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

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

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

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility.

In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

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

Methods for estimating a liability amount for PPAs

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

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

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

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

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

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

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

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

Moody's Related Research

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

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

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

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Exhibit DKA-4

Standard & Poor's Rating Services

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Corporate Methodology

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Corporate Methodology

1. Standard & Poor's Ratings Services is updating its criteria for rating corporate industrial companies and utilities. The criteria organize the analytical process according to a common framework and articulate the steps in developing the stand-alone credit profile (SACP) and issuer credit rating (ICR) for a corporate entity.

2. This article is related to our criteria article "Principles Of Credit Ratings," which we published on Feb. 16, 2011.

SUMMARY OF THE CRITERIA

3. The criteria describe the methodology we use to determine the SACP and ICR for corporate industrial companies and utilities. Our assessment reflects these companies' business risk profiles, their financial risk profiles, and other factors that may modify the SACP outcome (see "General Criteria: Stand-Alone Credit Profiles: One Component Of A Rating," published Oct. 1, 2010, for the definition of SACP). The criteria provide clarity on how we determine an issuer's SACP and ICR and are more specific in detailing the various factors of the analysis. The criteria also provide clear guidance on how we use these factors as part of determining an issuer's ICR. Standard & Poor's intends for these criteria to provide the market with a framework that clarifies our approach to fundamental analysis of corporate credit risks.

4. The business risk profile comprises the risk and return potential for a company in the markets in which it participates, the competitive climate within those markets (its industry risk), the country risks within those markets, and the competitive advantages and disadvantages the company has within those markets (its competitive position). The business risk profile affects the amount of financial risk that a company can bear at a given SACP level and constitutes the foundation for a company's expected economic success. We combine our assessments of industry risk, country risk, and competitive position to determine the assessment for a corporation's business risk profile.

5. The financial risk profile is the outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to the company's financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.

6. We then combine an issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor (see table 3). Additional rating factors can modify the anchor. These are: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. Comparable ratings analysis is the last analytical factor under the criteria to determine the final SACP on a company.

7. These criteria are complemented by industry-specific criteria called Key Credit Factors (KCFs). The KCFs describe the industry risk assessments associated with each sector and may identify sector-specific criteria that supersede certain sections of these criteria. As an example, the liquidity criteria state that the relevant KCF article may specify different standards than those stated within the liquidity criteria to evaluate companies that are part of exceptionally stable or

volatile industries. The KCFs may also define sector-specific criteria for one or more of the factors in the analysis. For example, the analysis of a regulated utility's competitive position is different from the methodology to evaluate the competitive position of an industrial company. The regulated utility KCF will describe the criteria we use to evaluate those companies' competitive positions (see "Key Credit Factors For The Regulated Utility Industry," published Nov. 19, 2013).

SCOPE OF THE CRITERIA

8. This methodology applies to nonfinancial corporate issuer credit ratings globally. Please see "Criteria Guidelines For Recovery Ratings On Global Industrial Issuers' Speculative-Grade Debt," published Aug. 10, 2009, and "2008 Corporate Criteria: Rating Each Issue," published April 15, 2008, for further information on our methodology for determining issue ratings. This methodology does not apply to the following sectors, based on the unique characteristics of these sectors, which require either a different framework of analysis or substantial modifications to one or more factors of analysis: project finance entities, project developers, transportation equipment leasing, auto rentals, commodities trading, investment holding companies and companies that maximize their returns by buying and selling equity holdings over time, Japanese general trading companies, corporate securitizations, nonprofit and cooperative organizations, master limited partnerships, general partnerships of master limited partnerships, and other entities whose cash flows are primarily derived from partially owned equity holdings.

IMPACT ON OUTSTANDING RATINGS

9. We expect about 5% of corporate industrial companies and utilities ratings within the scope of the criteria to change. Of that number, we expect approximately 90% to receive a one-notch change, with the majority of the remainder receiving a two-notch change. We expect the ratio of upgrades to downgrades to be around 3:1.

EFFECTIVE DATE AND TRANSITION

10. These criteria are effective immediately on the date of publication. We intend to complete our review of all affected ratings within the next six months.

METHODOLOGY

A. Corporate Ratings Framework

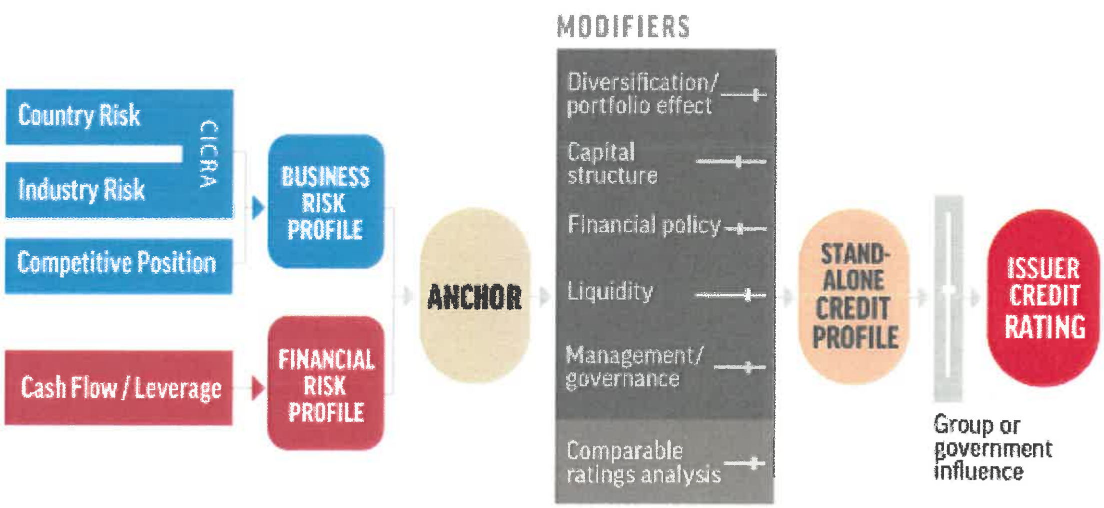
11. The corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several factors so that Standard & Poor's considers all salient issues. First we analyze the company's business risk profile, then evaluate its financial risk profile, then combine those to determine an issuer's anchor. We then analyze six factors that could potentially modify our anchor conclusion.

12. To determine the assessment for a corporate issuer's business risk profile, the criteria combine our assessments of industry risk, country risk, and competitive position. Cash flow/leverage analysis determines a company's financial risk profile assessment. The analysis then combines the corporate issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor. In general, the analysis weighs the business risk profile more heavily for investment-grade anchors, while the financial risk profile carries more weight for speculative-grade anchors.

13. After we determine the anchor, we use additional factors to modify the anchor. These factors are: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. The assessment of each factor can raise or lower the anchor by one or more notches--or have no effect. These conclusions take the form of assessments and descriptors for each factor that determine the number of notches to apply to the anchor.

14. The last analytical factor the criteria call for is comparable ratings analysis, which may raise or lower the anchor by one notch based on a holistic view of the company's credit characteristics.

Corporate Criteria Framework



15. The three analytic factors within the business risk profile generally are a blend of qualitative assessments and quantitative information. Qualitative assessments distinguish risk factors, such as a company's competitive advantages, that we use to assess its competitive position. Quantitative information includes, for example, historical cyclicality of revenues and profits that we review when assessing industry risk. It can also include the volatility and level of profitability we consider in order to assess a company's competitive position. The assessments for business risk profile are: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; and 6, vulnerable.

16. In assessing cash flow/leverage to determine the financial risk profile, the analysis focuses on quantitative measures. The assessments for financial risk profile are: 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; and 6, highly leveraged.

17. The ICR results from the combination of the SACP and the support framework, which determines the extent of the difference between the SACP and the ICR, if any, for group or government influence. Extraordinary influence is then captured in the ICR. Please see "Group Rating Methodology," published Nov. 19, 2013, and "Rating Government-Related Entities: Methodology And Assumptions," published Dec. 9, 2010, for our methodology on group and government influence.

18. Ongoing support or negative influence from a government (for government-related entities), or from a group, is factored into the SACP (see "SACP criteria"). While such ongoing support/negative influence does not affect the industry or country risk assessment, it can affect any other factor in business or financial risk. For example, such support or negative influence can affect: national industry analysis, other elements of competitive position, financial risk profile, the liquidity assessment, and comparable ratings analysis.

19. The application of these criteria will result in an SACP that could then be constrained by the relevant sovereign rating and transfer and convertibility (T&C) assessment affecting the entity when determining the ICR. In order for the final ICR to be higher than the applicable sovereign rating or T&C assessment, the entity will have to meet the conditions established in "Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions," published Nov. 19, 2013.

1. Determining the business risk profile assessment

20. Under the criteria, the combined assessments for country risk, industry risk, and competitive position determine a company's business risk profile assessment. A company's strengths or weaknesses in the marketplace are vital to its credit assessment. These strengths and weaknesses determine an issuer's capacity to generate cash flows in order to service its obligations in a timely fashion.

21. Industry risk, an integral part of the credit analysis, addresses the relative health and stability of the markets in which a company operates. The range of industry risk assessments is: 1, very low risk; 2, low risk; 3, intermediate risk; 4, moderately high risk; 5, high risk; and 6, very high risk. The treatment of industry risk is in section B.

22. Country risk addresses the economic risk, institutional and governance effectiveness risk, financial system risk, and payment culture or rule of law risk in the countries in which a company operates. The range of country risk assessments is: 1, very low risk; 2, low risk; 3, intermediate risk; 4, moderately high risk; 5, high risk; and 6, very high risk. The treatment of country risk is in section C.

23. The evaluation of an enterprise's competitive position identifies entities that are best positioned to take advantage of key industry drivers or to mitigate associated risks more effectively--and achieve a competitive advantage and a stronger business risk profile than that of entities that lack a strong value proposition or are more vulnerable to industry risks. The range of competitive position assessments is: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; and 6, vulnerable. The full treatment of competitive position is in section D.

24. The combined assessment for country risk and industry risk is known as the issuer's Corporate Industry and Country Risk Assessment (CICRA). Table 1 shows how to determine the combined assessment for country risk and industry risk.

Table 1

Determining The CICRA

	--Country risk assessment--					
Industry risk assessment	**1 (very low risk)**	**2 (low risk)**	**3 (intermediate risk)**	**4 (moderately high risk)**	**5 (high risk)**	**6 (very high risk)**
1 (very low risk)	1	1	1	2	4	5
2 (low risk)	2	2	2	3	4	5
3 (intermediate risk)	3	3	3	3	4	6
4 (moderately high risk)	4	4	4	4	5	6
5 (high risk)	5	5	5	5	5	6
6 (very high risk)	6	6	6	6	6	6

25. The CICRA is combined with a company's competitive position assessment in order to create the issuer's business risk profile assessment. Table 2 shows how we combine these assessments.

Table 2

Determining The Business Risk Profile Assessment

	--CICRA--					
Competitive position assessment	**1**	**2**	**3**	**4**	**5**	**6**
1 (excellent)	1	1	1	2	3*	5
2 (strong)	1	2	2	3	4	5
3 (satisfactory)	2	3	3	3	4	6
4 (fair)	3	4	4	4	5	6
5 (weak)	4	5	5	5	5	6
6 (vulnerable)	5	6	6	6	6	6

*See paragraph 26.

26. A small number of companies with a CICRA of 5 may be assigned a business risk profile assessment of 2 if all of the following conditions are met:

- The company's competitive position assessment is 1.
- The company's country risk assessment is no riskier than 3.
- The company produces significantly better-than-average industry profitability, as measured by the level and volatility of profits.
- The company's competitive position within its sector transcends its industry risks due to unique competitive advantages with its customers, strong operating efficiencies not enjoyed by the large majority of the industry, or scale/scope/diversity advantages that are well beyond the large majority of the industry.

27. For issuers with multiple business lines, the business risk profile assessment is based on our assessment of each of the factors--country risk, industry risk, and competitive position--as follows:

- Country risk: We use the weighted average of the country risk assessments for the company across all business lines that generate more than 5% of sales or where more than 5% of fixed assets are located.

- Industry risk: We use the weighted average of the industry risk assessments for all business lines representing more than 20% of the company's forecasted earnings, revenues or fixed assets, or other appropriate financial measures if earnings, revenue, or fixed assets do not accurately reflect the exposure to an industry.
- Competitive position: We assess all business lines identified above for the components competitive advantage, scope/scale/diversity, and operating efficiency (see section D). They are then blended using a weighted average of revenues, earnings, or assets to form the preliminary competitive position assessment. The level of profitability and volatility of profitability are then assessed based on the consolidated financials for the enterprise. The preliminary competitive position assessment is then blended with the profitability assessment, as per section D.5, to assess competitive position for the enterprise.

2. Determining the financial risk profile assessment

28. Under the criteria, cash flow/leverage analysis is the foundation for assessing a company's financial risk profile. The range of assessments for a company's cash flow/leverage is 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; and 6, highly leveraged. The full treatment of cash flow/leverage analysis is the subject of section E.

3. Merger of financial risk profile and business risk profile assessments

29. An issuer's business risk profile assessment and its financial risk profile assessment are combined to determine its anchor (see table 3). If we view an issuer's capital structure as unsustainable or if its obligations are currently vulnerable to nonpayment, and if the obligor is dependent upon favorable business, financial, and economic conditions to meet its commitments on its obligations, then we will determine the issuer's SACP using "Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings," published Oct. 1, 2012. If the issuer meets the conditions for assigning 'CCC+', 'CCC', 'CCC-', and 'CC' ratings, we will not apply Table 3.

Table 3

Combining The Business And Financial Risk Profiles To Determine The Anchor

	--Financial risk profile--					
Business risk profile	**1 (minimal)**	**2 (modest)**	**3 (intermediate)**	**4 (significant)**	**5 (aggressive)**	**6 (highly leveraged)**
1 (excellent)	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
2 (strong)	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
3 (satisfactory)	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
4 (fair)	bbb/bbb-	bbb-	bb+	bb	bb-	b
5 (weak)	bb+	bb+	bb	bb-	b+	b/b-
6 (vulnerable)	bb-	bb-	bb-/b+	b+	b	b-

30. When two anchor outcomes are listed for a given combination of business risk profile assessment and financial risk profile assessment, an issuer's anchor is determined as follows:

- When a company's financial risk profile is 4 or stronger (meaning, 1-4), its anchor is based on the comparative strength of its business risk profile. We consider our assessment of the business risk profile for corporate issuers to be points along a possible range. Consequently, each of these assessments that ultimately generate the business risk profile for a specific issuer can be at the upper or lower end of such a range. Issuers with stronger business risk profiles for the range of anchor outcomes will be assigned the higher anchor. Those with a weaker business risk profile for the range of anchor outcomes will be assigned the lower anchor.
- When a company's financial risk profile is 5 or 6, its anchor is based on the comparative strength of its financial risk

profile. Issuers with stronger cash flow/leverage ratios for the range of anchor outcomes will be assigned the higher anchor. Issuers with weaker cash flow/leverage ratios for the range of anchor outcomes will be assigned the lower anchor. For example, a company with a business risk profile of (1) excellent and a financial risk profile of (6) highly leveraged would generally be assigned an anchor of 'bb+' if its ratio of debt to EBITDA was 8x or greater and there were no offsetting factors to such a high level of leverage.

4. Building on the anchor

31. The analysis of diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance may raise or lower a company's anchor. The assessment of each modifier can raise or lower the anchor by one or more notches--or have no effect in some cases (see tables 4 and 5). We express these conclusions using specific assessments and descriptors that determine the number of notches to apply to the anchor. However, this notching in aggregate can't lower an issuer's anchor below 'b-' (see "Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings," published Oct. 1, 2012, for the methodology we use to assign 'CCC' and 'CC' category SACPs and ICRs to issuers).

32. The analysis of the modifier diversification/portfolio effect identifies the benefits of diversification across business lines. The diversification/portfolio effect assessments are 1, significant diversification; 2, moderate diversification; and 3, neutral. The impact of this factor on an issuer's anchor is based on the company's business risk profile assessment and is described in Table 4. Multiple earnings streams (which are evaluated within a firm's business risk profile) that are less-than-perfectly correlated reduce the risk of default of an issuer (see Appendix D). We determine the impact of this factor based on the business risk profile assessment because the benefits of diversification are significantly reduced with poor business prospects. The full treatment of diversification/portfolio effect analysis is the subject of section F.

Table 4

Modifier Step 1: Impact Of Diversification/Portfolio Effect On The Anchor

	--Business risk profile assessment--					
Diversification/portfolio effect	**1 (excellent)**	**2 (strong)**	**3 (satisfactory)**	**4 (fair)**	**5 (weak)**	**6 (vulnerable)**
1 (significant diversification)	+2 notches	+2 notches	+2 notches	+1 notch	+1 notch	0 notches
2 (moderate diversification)	+1 notch	+1 notch	+1 notch	+1 notch	0 notches	0 notches
3 (neutral)	0 notches	0 notches	0 notches	0 notches	0 notches	0 notches

33. After we adjust for the diversification/portfolio effect, we determine the impact of the other modifiers: capital structure, financial policy, liquidity, and management and governance. We apply these four modifiers in the order listed in Table 5. As we go down the list, a modifier may (or may not) change the anchor to a new range (one of the ranges in the four right-hand columns in the table). We'll choose the appropriate value from the new range, or column, to determine the next modifier's effect on the anchor. And so on, until we get to the last modifier on the list--management and governance. For example, let's assume that the anchor, after adjustment for diversification/portfolio effect but before adjusting for the other modifiers, is 'a'. If the capital structure assessment is very negative, the indicated anchor drops two notches, to 'bbb+'. So, to determine the impact of the next modifier--financial policy--we go to the column 'bbb+ to bbb-' and find the appropriate assessment--in this theoretical example, positive. Applying that assessment moves the anchor up one notch, to the 'a- and higher' category. In our example, liquidity is strong, so the impact is zero notches and the anchor remains unchanged. Management and governance is satisfactory, and thus the anchor remains 'a-' (see chart following table 5).

Table 5

Modifier Step 2: Impact Of Remaining Modifier Factors On The Anchor

	--Anchor range--			
	'a-' and higher	**'bbb+' to 'bbb-'**	**'bb+' to 'bb-'**	**'b+' and lower**
Factor/Assessment				
Capital structure (see section G)				
1 (Very positive)	2 notches	2 notches	2 notches	2 notches
2 (Positive)	1 notch	1 notch	1 notch	1 notch
3 (Neutral)	0 notches	0 notches	0 notches	0 notches
4 (Negative)	-1 notch	-1 notch	-1 notch	-1 notch
5 (Very negative)	-2 or more notches	-2 or more notches	-2 or more notches	-2 notches
Financial policy (FP; see section H)				
1 (Positive)	+1 notch if M&G is at least satisfactory	+1 notch if M&G is at least satisfactory	+1 notch if liquidity is at least adequate and M&G is at least satisfactory	+1 notch if liquidity is at least adequate and M&G is at least satisfactory
2 (Neutral)	0 notches	0 notches	0 notches	0 notches
3 (Negative)	-1 to -3 notches(1)	-1 to -3 notches(1)	-1 to -2 notches(1)	-1 notch
4 (FS-4, FS-5, FS-6, FS-6 [minus])	N/A(2)	N/A(2)	N/A(2)	N/A(2)
Liquidity (see section I)				
1 (Exceptional)	0 notches	0 notches	0 notches	+1 notch if FP is positive, neutral, FS-4, or FS-5 (3)
2 (Strong)	0 notches	0 notches	0 notches	+1 notch if FP is positive, neutral, FS-4, or FS-5 (3)
3 (Adequate)	0 notches	0 notches	0 notches	0 notches
4 (Less than adequate [4])	N/A	N/A	-1 notch(5)	0 notches
5 (Weak)	N/A	N/A	N/A	'b-' cap on SACP
Management and governance (M&G; see section J)				
1 (Strong)	0 notches	0 notches	0, +1 notches(6)	0, +1 notches(6)
2 (Satisfactory)	0 notches	0 notches	0 notches	0 notches
3 (Fair)	-1 notch	0 notches	0 notches	0 notches
4 (Weak)	-2 or more notches(7)	-2 or more notches(7)	-1 or more notches(7)	-1 or more notches(7)

(1) Number of notches depends on potential incremental leverage. (2) See "Assessing Financial Policy," section H.2. (3) Additional notch applies only if we expect liquidity to remain exceptional or strong. (4) See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013. SACP is capped at 'bb+.' (5) If issuer SACP is 'bb+' due to cap, there is no further notching. (6) This adjustment is one notch if we have not already captured benefits of strong management and governance in the analysis of the issuer's competitive position. (7) Number of notches depends upon the degree of negative effect to the enterprise's risk profile.

Example: How Remaining Modifiers Can Change The Anchor

*After adjusting for diversification/portfolio effect. See paragraph 33.

34. Our analysis of a firm's capital structure assesses risks in the firm's capital structure that may not arise in the review of its cash flow/leverage. These risks include the currency risk of debt, debt maturity profile, interest rate risk of debt, and an investments subfactor. We assess a corporate issuer's capital structure on a scale of 1, very positive; 2, positive; 3, neutral; 4, negative; and 5, very negative. The full treatment of capital structure is the subject of section G.

35. Financial policy serves to refine the view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage, capital structure, and liquidity analyses. Those assumptions do not always reflect or adequately capture the long-term risks of a firm's financial policy. The financial policy assessment is, therefore, a measure of the degree to which owner/managerial decision-making can affect the predictability of a company's financial risk profile. We assess financial policy as 1) positive, 2) neutral, 3) negative, or as being owned by a financial sponsor. We further identify financial sponsor-owned companies as "FS-4", "FS-5", "FS-6", or "FS-6 (minus)." The full treatment of financial policy analysis is the subject of section H.

36. Our assessment of liquidity focuses on the monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis also assesses the potential for a company to breach covenant tests tied to declines in earnings before interest, taxes, depreciation, and amortization (EBITDA). The methodology incorporates a qualitative analysis that addresses such factors as the ability to absorb high-impact, low-probability events, the nature of bank relationships, the level of standing in credit markets, and the degree of prudence of the company's financial risk management. The liquidity assessments are 1, exceptional; 2, strong; 3, adequate; 4, less than adequate; and 5, weak. An SACP is capped at 'bb+' for issuers whose liquidity is less than adequate and 'b-' for issuers whose liquidity is weak, regardless of the assessment of any modifiers or comparable ratings analysis. (For the complete methodology on assessing corporate issuers' liquidity, see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013.)

37. The analysis of management and governance addresses how management's strategic competence, organizational effectiveness, risk management, and governance practices shape the company's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. The range of management and governance assessments is: 1, strong; 2, satisfactory; 3, fair; and 4, weak. Typically, investment-grade anchor outcomes reflect strong or satisfactory management and governance, so there is no incremental benefit. Alternatively, a fair or weak assessment of management and governance can lead to a lower anchor. Also, a strong assessment for management and governance for a weaker entity is viewed as a favorable factor, under the criteria, and can have a

positive impact on the final SACP outcome. For the full treatment of management and governance, see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012.

5. Comparable ratings analysis

38. The anchor, after adjusting for the modifiers, could change one notch up or down in order to arrive at an issuer's SACP based on our comparable ratings analysis, which is a holistic review of a company's stand-alone credit risk profile, in which we evaluate an issuer's credit characteristics in aggregate. A positive assessment leads to a one-notch improvement, a negative assessment leads to a one-notch reduction, and a neutral assessment indicates no change to the anchor. The application of comparable ratings analysis reflects the need to 'fine-tune' ratings outcomes, even after the use of each of the other modifiers. A positive or negative assessment is therefore likely to be common rather than exceptional.

B. Industry Risk

39. The analysis of industry risk addresses the major factors that Standard & Poor's believes affect the risks that entities face in their respective industries. (See "Methodology: Industry Risk," published Nov. 19, 2013.)

C. Country Risk

40. The analysis of country risk addresses the major factors that Standard & Poor's believes affect the country where entities operate. Country risks, which include economic, institutional and governance effectiveness, financial system, and payment culture/rule of law risks, influence overall credit risks for every rated corporate entity. (See "Country Risk Assessment Methodology And Assumptions," published Nov. 19, 2013.)

1. Assessing country risk for corporate issuers

41. The following paragraphs explain how the criteria determine the country risk assessment for a corporate entity. Once it's determined, we combine the country risk assessment with the issuer's industry risk assessment to calculate the issuer's CICRA (see section A, table 1). The CICRA is one of the factors of the issuer's business risk profile. If an issuer has very low to intermediate exposure to country risk, as represented by a country risk assessment of 1, 2, or 3, country risk is neutral to an issuer's CICRA. But if an issuer has moderately high to very high exposure to country risk, as represented by a country risk assessment of 4, 5, or 6, the issuer's CICRA could be influenced by its country risk assessment.

42. Corporate entities operating within a single country will receive a country risk assessment for that jurisdiction. For entities with exposure to more than one country, the criteria prospectively measure the proportion of exposure to each country based on forecasted EBITDA, revenues, or fixed assets, or other appropriate financial measures if EBITDA, revenue, or fixed assets do not accurately reflect the exposure to that jurisdiction.

43. Arriving at a company's blended country risk assessment involves multiplying its weighted-average exposures for each country by each country's risk assessment and then adding those numbers. For the weighted-average calculation, the criteria consider countries where the company generates more than 5% of its sales or where more than 5% of its fixed assets are located, and all weightings are rounded to the nearest 5% before averaging. We round the assessment to the

nearest integer, so a weighted assessment of 2.2 rounds to 2, and a weighted assessment of 2.6 rounds to 3 (see table 6).

Table 6

Hypothetical Example Of Weighted-Average Country Risk For A Corporate Entity

Country	Weighting (% of business*)	Country risk§	Weighted country risk
Country A	45	1	0.45
Country B	20	2	0.4
Country C	15	1	0.15
Country D	10	4	0.4
Country E	10	2	0.2
Weighted-average country risk assessment (rounded to the nearest whole number)	--	--	2

*Using EBITDA, revenues, fixed assets, or other financial measures as appropriate. §On a scale from 1-6, lowest to highest risk.

44. A weak link approach, which helps us calculate a blended country risk assessment for companies with exposure to more than one country, works as follows: If fixed assets are based in a higher-risk country but products are exported to a lower-risk country, the company's exposure would be to the higher-risk country. Similarly, if fixed assets are based in a lower-risk country but export revenues are generated from a higher-risk country and cannot be easily redirected elsewhere, we measure exposure to the higher-risk country. If a company's supplier is located in a higher-risk country, and its supply needs cannot be easily redirected elsewhere, we measure exposure to the higher-risk country. Conversely, if the supply chain can be re-sourced easily to another country, we would not measure exposure to the higher risk country.

45. Country risk can be mitigated for a company located in a single jurisdiction in the following narrow case. For a company that exports the majority of its products overseas and has no direct exposure to a country's banking system that would affect its funding, debt servicing, liquidity, or ability to transfer payments from or to its key counterparties, we could reduce the country risk assessment by one category (e.g., 5 to 4) to determine the adjusted country risk assessment. This would only apply for countries where we considered the financial system risk subfactor a constraint on the overall country risk assessment for that country. For such a company, other country risks are not mitigated: Economic risk still applies, albeit less of a risk than for a company that sells domestically (potential currency volatility remains a risk for exporters); institutional and governance effectiveness risk still applies (political risk may place assets at risk); and payment culture/rule of law risk still applies (legal risks may place assets and cross-border contracts at risk).

46. Companies will often disclose aggregated information for blocks of countries, rather than disclosing individual country information. If the information we need to estimate exposure for all countries is not available, we use regional risk assessments. Regional risk assessments are calculated as averages of the unadjusted country risk assessments, weighted by gross domestic product of each country in a defined region. The criteria assess regional risk on a 1-6 scale (strongest to weakest). Please see Appendix A, Table 26, which lists the constituent countries of the regions.

47. If an issuer does not disclose its country-level exposure or regional-level exposure, individual country risk exposures or regional exposures will be estimated.

2. Adjusting the country risk assessment for diversity

48. We will adjust the country risk assessment for a company that operates in multiple jurisdictions and demonstrates a high degree of diversity of country risk exposures. As a result of this diversification, the company could have less exposure to country risk than the rounded weighted average of its exposures might indicate. Accordingly, the country risk assessment for a corporate entity could be adjusted if an issuer meets the conditions outlined in paragraph 49.

49. The preliminary country risk assessment is raised by one category to reflect diversity if all of the following four conditions are met:

- If the company's head office, as defined in paragraph 51, is located in a country with a risk assessment stronger than the preliminary country risk assessment;
- If no country, with a country risk assessment equal to or weaker than the company's preliminary country risk assessment, represents or is expected to represent more than 20% of revenues, EBITDA, fixed assets, or other appropriate financial measures;
- If the company is primarily funded at the holding level, or through a finance subsidiary in a similar or stronger country risk environment than the holding company, or if any local funding could be very rapidly substituted at the holding level; and
- If the company's industry risk assessment is '4' or stronger.

50. The country risk assessment for companies that have 75% or more exposure to one jurisdiction cannot be improved and will, in most instances, equal the country risk assessment of that jurisdiction. But the country risk assessment for companies that have 75% or more exposure to one jurisdiction can be weakened if the balance of exposure is to higher risk jurisdictions.

51. We consider the location of a corporate head office relevant to overall risk exposure because it influences the perception of a company and its reputation--and can affect the company's access to capital. We determine the location of the head office on the basis of 'de facto' head office operations rather than just considering the jurisdiction of incorporation or stock market listing for public companies. De facto head office operations refers to the country where executive management and centralized high-level corporate activities occur, including strategic planning and capital raising. If such activities occur in different countries, we take the weakest country risk assessment applicable for the countries in which those activities take place.

D. Competitive Position

52. Competitive position encompasses company-specific factors that can add to, or partly offset, industry risk and country risk--the two other major factors of a company's business risk profile.

53. Competitive position takes into account a company's: 1) competitive advantage, 2) scale, scope, and diversity, 3) operating efficiency, and 4) profitability. A company's strengths and weaknesses on the first three components shape its competitiveness in the marketplace and the sustainability or vulnerability of its revenues and profit. Profitability can either confirm our initial assessment of competitive position or modify it, positively or negatively. A stronger-than-industry-average set of competitive position characteristics will strengthen a company's business risk profile. Conversely, a weaker-than-industry-average set of competitive position characteristics will weaken a

company's business risk profile.

54. These criteria describe how we develop a competitive position assessment. They provide guidance on how we assess each component based on a number of subfactors. The criteria define the weighting rules applied to derive a preliminary competitive position assessment. And they outline how this preliminary assessment can be maintained, raised, or lowered based on a company's profitability. Standard & Poor's competitive position analysis is both qualitative and quantitative.

1. The components of competitive position

55. A company's competitive position assessment can be: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; or 6, vulnerable.

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

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

57. We follow four steps to arrive at the competitive position assessment. First, we separately assess competitive advantage; scale, scope, and diversity; and operating efficiency (excluding any benefits or risks already captured in the issuer's CICRA assessment). Second, we apply weighting factors to these three components to derive a weighted-average assessment that translates into a preliminary competitive position assessment. Third, we assess profitability. Finally, we combine the preliminary competitive position assessment and the profitability assessment to determine the final competitive position assessment. Profitability can confirm, or influence positively or negatively, the competitive position assessment.

58. We assess the relative strength of each of the first three components by reviewing a variety of subfactors (see table 7). When quantitative metrics are relevant and available, we use them to evaluate these subfactors. However, our overall assessment of each component is qualitative. Our evaluation is forward-looking; we use historical data only to the extent that they provide insight into future trends.

59. We evaluate profitability by assessing two subcomponents: level of profitability (measured by historical and projected nominal levels of return on capital, EBITDA margin, and/or sector-specific metrics) and volatility of profitability (measured by historically observed and expected fluctuations in EBITDA, return on capital, EBITDA margin, or sector specific metrics). We assess both subcomponents in the context of the company's industry.

Table 7

Competitive Position Components And Subfactors

Component	Explanation	Subfactors
1. Competitive advantage (see Appendix B, section 1)	The strategic positioning and attractiveness to customers of a company's products or services, and the fragility or sustainability of its business model	• Strategy • Differentiation/uniqueness/product positioning/bundling • Brand reputation and marketing • Product and/or service quality • Barriers to entry and customers' switching costs • Technological advantage and capabilities and vulnerability to/ability to drive technological displacement • Asset base characteristics
2. Scale, scope, and diversity (see Appendix B, section 2)	The concentration or diversification of business activities	• Diversity of products or services • Geographic diversity • Volumes, size of markets and revenues, and market share • Maturity of products or services
3. Operating efficiency (see Appendix B, section 3)	The quality and flexibility of a company's asset base and its cost management and structure	• Cost structure • Manufacturing processes • Working capital management • Technology
4. Profitability		• Level of profitability (historical and projected return on capital, EBITDA margin, and/or sector-relevant measure) • Volatility of profitability

2. Assessing competitive advantage, scale, scope, and diversity, and operating efficiency

60. We assess competitive advantage; scale, scope, and diversity; and operating efficiency as: 1, strong; 2, strong/adequate; 3, adequate; 4, adequate/weak; or 5, weak. Tables 8, 9, and 10 provide guidance for assessing each component.

61. In assessing the components' relative strength, we place significant emphasis on comparative analysis. Peer comparisons provide context for evaluating the subfactors and the resulting component assessment. We review company-specific characteristics in the context of the company's industry, not just its narrower subsector. (See list of industries and subsectors in Appendix B, table 27.) For example, when evaluating an airline, we will benchmark the assessment against peers in the broader transportation-cyclical industry (including the marine and trucking subsectors), and not just against other airlines. Likewise, we will compare a home furnishing manufacturer with other companies in the consumer durables industry, including makers of appliances or leisure products. We might occasionally extend the comparison to other industries if, for instance, a company's business lines cross several industries, or if there are a limited number of rated peers in an industry, subsector, or region.

62. An assessment of strong means that the company's strengths on that component outweigh its weaknesses, and that the combination of relevant subfactors results in lower-than-average business risk in the industry. An assessment of adequate means that the company's strengths and weaknesses with respect to that component are balanced and that the relevant subfactors add up to average business risk in the industry. A weak assessment means that the company's weaknesses on that component override any strengths and that its subfactors, in total, reveal higher-than-average business risk in the industry.

63. Where a component is not clearly strong or adequate, we may assess it as strong/adequate. A component that is not clearly adequate or weak may end up as adequate/weak.

64. Although we review each subfactor, we don't assess each individually--and we seek to understand how they may reinforce or weaken each other. A component's assessment combines the relative strengths and importance of its subfactors. For any company, one or more subfactors can be unusually important--even factors that aren't common in the industry. Industry KCF articles identify subfactors that are consistently more important, or happen not to be relevant, in a given industry.

65. Not all subfactors may be equally important, and a single one's strength or weakness may outweigh all the others. For example, if notwithstanding a track record of successful product launches and its strong brand equity, a company's strategy doesn't appear adaptable, in our view, to changing competitive dynamics in the industry, we will likely not assess its competitive advantage as strong. Similarly, if its revenues came disproportionately from a narrow product line, we might view this as compounding its risk of exposure to a small geographic market and, thus, assess its scale, scope, and diversity component as weak.

66. From time to time companies will, as a result of shifting industry dynamics or strategies, expand or shrink their product or service lineups, alter their cost structures, encounter new competition, or have to adapt to new regulatory environments. In such instances, we will reevaluate all relevant subfactors (and component assessments).

Table 8

Competitive Advantage Assessment

Qualifier	What it means	Guidance
Strong	• The company has a major competitive advantage due to one or a combination of factors that supports revenue and profit growth, combined with lower-than-average volatility of profits. • There are strong prospects that the company can sustain this advantage over the long term. • This should enable the company to withstand economic downturns and competitive and technological threats better than its competitors can. • Any weaknesses in one or more subfactors are more than offset by strengths in other subfactors that produce sustainable and profitable revenue growth.	• The company's business strategy is highly consistent with, and adaptable to, industry trends and conditions and supports its leadership in the marketplace. • It consistently develops and markets well-differentiated products or services, aligns products with market demand, and enhances the attractiveness or uniqueness of its value proposition through bundling. • Its superior track record of product development, service quality, and customer satisfaction and retention support its ability to maintain or improve its market share. • Its products or services command a clear price premium relative to its competitors' thanks to its brand equity, technological leadership, or quality of service; it is able to sustain this advantage with innovation and effective marketing. • It benefits from barriers to entry from regulation, market characteristics, or intrinsic benefits (such as patents, technology, or customer relationships) that effectively reduce the threat of new competition. • It has demonstrated a commitment and ability to effectively reinvest in its asset base, as evidenced by a continuous pipeline of new products and/or improvement in key capabilities, such as employee retention, customer care, distribution, and supplier relations. These tangible and intangible assets support long term prospects of sustainable and profitable growth.
Adequate	• The company has some competitive advantages, but not so large as to create a superior business model or durable benefit compared to its peers'. • It has some but not all drivers of competitiveness. Certain factors support the business' long-term viability and should result in average profitability and average profit volatility during recessions or periods of increased competition. However, these drivers are partially offset by the company's disadvantages or lack of sustainability of other factors.	• The company's strategy is well adapted to marketplace conditions, but it is not necessarily a leader in setting industry trends. • It exhibits neither superior nor subpar abilities with respect to product or service differentiation and positioning. • Its products command no price premium or advantage relative to competing brands as a result of its brand equity or its technological positioning. • It may enjoy some barriers to entry that provide some defense against competitors but don't overpower them. It faces some risk of product/service displacement or substitution longer term. • Its metrics of product or service quality and customer satisfaction or retention are in line with its industry's average. The company could lose customers to competitors if it makes operational missteps. • Its asset profile does not exhibit particularly superior or inferior characteristics compared to other industry participants. These assets generate consistent revenue and profit growth although long-term prospects are subject to some uncertainty.

Weak	• The company has few, if any, competitive advantages and a number of competitive disadvantages. • Because the company lacks many competitive advantages, its long-term prospects are uncertain, and its profit volatility is likely to be higher than average for its industry. • The company is less likely than its competitors to withstand economic, competitive, or technological threats. • Alternatively, the company has weaknesses in one or more subfactors that could keep its profitability below average and its profit volatility above average during economic downturns or periods of increased competition.	• The company's strategy is inconsistent with, or not well adapted to, marketplace trends and conditions. • There is evidence of little innovation, slowness in developing and marketing new products, an inability to raise prices, and/or ineffective bundling. • Its products generally enjoy no price premium relative to competing brands and it often has to sell its products at a lower price than its peers can command. • It has suffered or is at risk of suffering customer defections due to falling quality and because customers perceive its products or services to be less valuable than those of its competitors. • Its revenues and market shares are vulnerable to aggressive pricing by existing or new competitors or to technological displacement risks over the near to medium term. • Its metrics of product or service quality and customer satisfaction or retention are weaker than the industry average. • Its reinvestment in its business is lower than its peers', its ability to retain operational talent is limited, its distribution network is inefficient, and its revenue could stagnate or decline as result.

Table 9

Scale, Scope, And Diversity

Qualifier	What it means	Guidance
Strong	• The company's overall scale, scope, and diversity supports stable revenues and profits by rendering it essentially invulnerable to all but the most disruptive combinations of adverse factors, events, or trends. • Its significant advantages in scale, scope, and diversity enable it to withstand economic, regional, competitive, and technological threats better than its competitors can.	• The company's range of products or services is among the most comprehensive in its sector. It derives its revenue and profits from a broader set of products or services than the industry average. • Its products and services enjoy industry-leading market shares relative to other participants in its industry. • It does not rely on a particular customer or small group of customers. If it does, the customer(s) is/are of high credit quality, their demand is highly sustainable, or the company and its customer(s) have significant interdependence. • It does not depend on any particular supplier or related group of suppliers that it could not easily replace. If it does, the supplier(s) is/are of high credit quality, or the company and its supplier(s) have significant interdependence. • It enjoys broader geographic diversity than its peers and doesn't overly depend on a single regional or local market. If it does, the market is local, often for regulatory reasons. The company's production or service centers are diversified across several locations. • It holds a strategic investment that provides positive business diversification.
Adequate	• The company's overall scale, scope, and diversity is comparable to its peers'. • Its ability to withstand economic, competitive, or technological threats is comparable to the ability of others within its sector.	• The company has a broad range of products or services compared with its competitors and doesn't depend on a particular product or service for the majority of its revenues and profits. • Its market share is average compared with that of its competitors. • Its dependence on or concentration of key customers is no higher than the industry average, and the loss of a top customer would be unlikely to pose a high risk to its business stability. • It isn't overly dependent on any supplier or regional group of suppliers that it couldn't easily replace. • It doesn't depend excessively on a single local or regional market, and its geographic footprint of production and revenue compares with that of other industry participants.

Weak	• The company's lack of scale, scope, and diversity compromises the stability and sustainability of its revenues and profits. • The company's vulnerability to, or reliance on, various elements of scale, scope, and diversity leaves it less likely than its competitors to withstand economic, competitive, or technological threats.	• The company's product or service lineup is somewhat limited compared to those of its sector peers. The company derives its profits from a narrow group of products or services, and has not achieved significant market share compared with its peers. • Demand for its products or services is lower than for its competitors', and this trend isn't improving. • It relies heavily on a particular customer or small group of customers, and the characteristics of the customer base do not mitigate this risk. • It depends on a particular supplier or group of suppliers, which it would not be able to easily replace without incurring high switching costs. • It depends disproportionately on a single local or regional economy for selling its goods or services, and the company's industry is global. • Key production assets are concentrated by location, and the company has limited ability to quickly replace them without incurring high costs relative to its profits.

Table 10

Operating Efficiency Assessment

Qualifier	What it means	Guidance
Strong	• The company maximizes revenues and profits via intelligent use of assets and by minimizing costs and increasing efficiency. • The company's cost structure should enable it to withstand economic downturns better than its peers.	• The company has a lower cost structure than its peers resulting in higher profits or margins even if capacity utilization or demand are well below ideal levels and during down economic and industry cycles. • It has demonstrated its ability to efficiently manage fixed and variable costs in cyclical downturns, and has a history of successful and often ongoing cost reductions programs. • Its capacity utilization is close to optimal at the peak of the industry cycle and outperforms the industry average over the cycle. • It has demonstrated that it can pass along increases in input costs and we expect this will continue. • It has a very high ability to adjust production and labor costs in response to changes in demand without repercussions for product quality, or has demonstrated the ability to operate very profitably in a more costly or less flexible labor environment. • Its suppliers have demonstrated an ability to meet swings in demand without causing bottlenecks or quality issues, and can absorb all but the most severe supply chain disruptions. • It has superior working capital management, as evidenced by a consistently better-than-average "cash conversion cycle" and other working capital metrics, supporting higher cash flow and lower funding costs. • Its investments in technology are likely to increase revenue growth and/or improve its cost structure and operating efficiency.

Adequate	• A combination of cost structure and efficiency should support sustainable profits with average profit volatility relative to the company's peers. Its cost structure is similar to its peers'.	• The company has demonstrated the ability to manage some fixed and most variable costs except during periods of extremely weak demand, and has some history of cutting costs in good and bad times. • Its cost structure permits some profitability even if capacity utilization or customer demand is well below ideal levels. The company can at least break even during most of the industry/demand cycle. • Its cost structure is in line with its peers'. For example, its selling, general, and administrative (SG&A) expense as a percent of revenue is similar to its peers' and is likely to be stable. • It has demonstrated an ability to adjust labor costs in most scenarios without hurting product output and quality, or can operate profitability in a more costly or less flexible labor environment; it has some success passing on input cost increases, although perhaps only partially or with time lag. • Its suppliers have met typical swings in demand without causing widespread bottlenecks or quality issues, and the company has some capacity to withstand limited supply chain disruptions. • It has good working capital management, evidenced by its cash conversion cycle and working capital metrics that are on par with its peers'. • Its investments in technology are likely to help it at least maintain its cost structure and current level of operating efficiency.
Weak	• The company's operating efficiency leaves it with lower profitability than its peers' due to lower asset utilization and/or a higher, less flexible cost structure.	• The company's cost structure permits better-than-marginal profitability only if capacity utilization is at the top of the cycle or during periods of strong demand. The company needs solid and sustained industry conditions to generate fair profitability. • It has limited success or capability of managing fixed costs and even most typically variable costs are fixed in the next two to three years. • It has a limited track record of successful cost reductions, such as reducing labor costs in the face of swings in demand, or it has limited ability to pass along increases in input costs. • Its costs are higher than its peers'. For example, the company's SG&A expense as a percent of revenue is above that of its peers, and likely to remain so. • Its suppliers may face bottlenecks or quality issues in the event of modest swings in demand, or have limited technological capabilities. There is evidence that a limited supply chain disruption would make it difficult for suppliers to meet their commitments to the company. • Its working capital management is weak, as evidenced by working capital metrics that are significantly worse than those of its peers, resulting in lower cash flow and higher funding costs. • It lacks investments in technology, which could hurt is revenue growth and/or result in a higher cost structure and less efficient operations relative to its peers'.

3. Determining the preliminary competitive position assessment: Competitive position group profile and category weightings

67. After assessing competitive advantage; scale, scope, and diversity; and operating efficiency, we determine a company's preliminary competitive position assessment by ascribing a specific weight to each component. The weightings depend on the company's Competitive Position Group Profile (CPGP).

68. There are six possible CPGPs: 1) services and product focus, 2) product focus/scale driven, 3) capital or asset focus, 4) commodity focus/cost driven, 5) commodity focus/scale driven, and 6) national industry and utilities (see table 11 for definitions and characteristics).

Table 11

Competitive Position Group Profile (CPGP)

	Definition and characteristics	Examples
Services and product focus	Brands, product quality or technology, and service reputation are typically key differentiating factors for competing in the industry. Capital intensity is typically low to moderate, although supporting the brand often requires ongoing reinvestment in the asset base.	Typically, these are companies in consumer-facing light manufacturing or service industries. Examples include branded drug manufacturers, software companies, and packaged food.
Product focus/scale driven	Product and geographic diversity, as well as scale and market position are key differentiating factors. Sophisticated technology and stringent quality controls heighten risk of product concentration. Product preferences or sales relationships are more important than branding or pricing. Cost structure is relatively unimportant.	The sector most applicable is medical device/equipment manufacturers, particularly at the higher end of the technology scale. These companies largely sell through intermediaries, as opposed to directly to the consumer.
Capital or asset focus	Sizable capital investments are generally required to sustain market position in the industry. Brand identification is of limited importance, although product and service quality often remain differentiating factors.	Heavy manufacturing industries typically fall into this category. Examples include telecom infrastructure manufacturers and semiconductor makers.
Commodity focus/cost driven	Cost position and efficiency of production assets are more important than size, scope, and diversification. Brand identification is of limited importance	Typically, these are companies that manufacture products from natural resources that are used as raw materials by other industries. Examples include forest and paper products companies that harvest timber or produce pulp, packaging paper, or wood products.
Commodity focus/scale driven	Pure commodity companies have little product differentiation, and tend to compete on price and availability. Where present, brand recognition or product differences are secondary or of less importance.	Examples range from pure commodity producers and most oil and gas upstream producers, to some producers with modest product or brand differentiation, such as commodity foods.
National industries and utilities	Government policy or control, regulation, and taxation and tariff policies significantly affect the competitive dynamics of the industry (see paragraphs 72-73).	An example is a water-utility company in an emerging market.

69. The nature of competition and key success factors are generally prescribed by industry characteristics, but vary by company. Where service, product quality, or brand equity are important competitive factors, we'll give the competitive advantage component of our overall assessment a higher weighting. Conversely, if the company produces a commodity product, differentiation comes less into play, and we will more heavily weight scale, scope, and diversity as well as operating efficiency (see table 12).

Table 12

Competitive Position Group Profiles (CPGPs) And Category Weightings

Component	--(%)--					
	Services and product focus	**Product focus/scale driven**	**Capital or asset focus**	**Commodity focus/cost driven**	**Commodity focus/scale driven**	**National industries and utilities**
1. Competitive advantage	45	35	30	15	10	60
2. Scale, scope, and diversity	30	50	30	35	55	20
3. Operating efficiency	25	15	40	50	35	20
Total	100	100	100	100	100	100
Weighted-average assessment*	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0	1.0-5.0

*1 (strong), 2 (strong/adequate), 3 (adequate), 4 (adequate/weak), 5 (weak).

70. We place each of the defined industries (see Appendix B, table 27) into one of the six CPGPs (see above and Appendix B, table 27). This is merely a starting point for the analysis, since we recognize that some industries are less homogenous than others, and that company-specific strategies do affect the basis of competition.

71. In fact, the criteria allow for flexibility in selecting a company's group profile (with its category weightings). Reasons for selecting a profile different than the one suggested in the guidance table could include:

- The industry is heterogeneous, meaning that the nature of competition differs from one subsector to the next, and possibly even within subsectors. The KCF article for the industry will identify such circumstances.
- A company's strategy could affect the relative importance of its key factors of competition.

72. For example, the standard CPGP for the telecom and cable industry is services and product focus. While this may be an appropriate group profile for carriers and service providers, an infrastructure provider may be better analyzed under the capital or asset focus group profile. Other examples: In the capital goods industry, a construction equipment rental company may be analyzed under the capital or asset focus group profile, owing to the importance of efficiently managing the capital spending cycle in this segment of the industry, whereas a provider of hardware, software, and services for industrial automation might be analyzed under the services and product focus group profile, if we believe it can achieve differentiation in the marketplace based on product performance, technology innovation, and service.

73. In some industries, the effects of government policy, regulation, government control, and taxation and tariff policies can significantly alter the competitive dynamics, depending on the country in which a company operates. That can alter our assessment of a company's competitive advantage; scale, size, and diversity; or operating efficiency. When industries in given countries have risks that differ materially from those captured in our global industry risk profile and assessment (see "Methodology: Industry Risk," published Nov. 19, 2013, section B), we will weight competitive advantage more heavily to capture the effect, positive or negative, on competitive dynamics. The assessment of competitive advantage; scale, size, and diversity; and operating efficiency will reflect advantages or disadvantages based on these national industry risk factors. Table 13 identifies the circumstances under which national industry risk factors are positive or negative.

Table 13

National Industry Risk Factors	
National industry risk factors are positive	• Government policy including regulation, ownership, and taxation is supportive and has a good track record of mitigating risks to the stability of industry margins. • Any government ownership, tariff, and taxation policy supports growth prospects for revenues and profit generation. • There is very little discernible risk of negative policy, regulatory, ownership, or taxation changes that could threaten business stability.
National industry risk factors are negative	• Government policy and regulation has a weak track record of stabilizing margins and reducing industry risks. • Any government ownership, tariff, and taxation policy undermine growth prospects for revenues and profit generation. • There is an increasing risk of negative policy, ownership, and taxation changes that could undermine industry stability.

74. When national industry risk factors are positive for a company, typically they support revenue growth, profit growth, higher EBITDA margins, and/or lower-than-average volatility of profits. Often, these benefits provide barriers to entry that impede or even bar new market entrants, which should be reflected in the competitive advantage assessment. These benefits may also include risk mitigants that enable a company to withstand economic downturns and competitive and technological threats better in its local markets than its global competitors can. The scale, scope, and diversity assessment might also benefit from these policies if the company is able to withstand economic, regional, competitive, and technological threats better than its global competitors can. Likewise, the company's operating efficiency assessment may improve if, as a result, it is better able than its global competitors to withstand economic downturns, taking into account its cost structure.

75. Conversely, when national industry risk factors are negative for a company, typically they detract from revenue growth and profit growth, shrink EBITDA margins, and/or increase the average volatility of profits. The company may also have less protection against economic downturns and competitive and technological threats within its local markets than its global competitors do. We may also adjust the company's scale, scope, and diversity assessment lower if, as a result of these policies, it is less able to withstand economic, regional, competitive, and technological threats than its global competitors can. Likewise, we may adjust its operating efficiency assessment lower if, as a result of these policies, it is less able to withstand economic downturns, taking into account the company's cost structure.

76. An example of when we might use a national industry risk factor would be for a telecommunications network owner that benefits from a monopoly network position, supported by substantial capital barriers to entry, and as a result is subject to regulated pricing for its services. Accordingly, in contrast to a typical telecommunications company, our analysis of the company's competitive position would focus more heavily on the monopoly nature of its operations, as well as the nature and reliability of the operator's regulatory framework in supporting future revenue and earnings. If we viewed the regulatory framework as being supportive of the group's future earnings stability, and we considered its

monopoly position to be sustainable, we would assess these national industry risk factors as positive in our assessment of the group's competitive position.

77. The weighted average assessment translates into the preliminary competitive position assessment on a scale of 1 to 6, where one is best. Table 14 describes the matrix we use to translate the weighted average assessment of the three components into the preliminary competitive position assessment.

Table 14

Translation Table For Converting Weighted-Average Assessments Into Preliminary Competitive Position Assessments

Weighted average assessment range	Preliminary competitive position assessment
1.00 – 1.50	1
>1.50 – 2.25	2
>2.25 – 3.00	3
>3.00 – 3.75	4
>3.75 – 4.50	5
>4.50 – 5.00	6

4. Assessing profitability

78. We assess profitability on the same scale of 1 to 6 as the competitive position assessment.

79. The profitability assessment consists of two subcomponents: level of profitability and the volatility of profitability, which we assess separately. We use a matrix to combine these into the final profitability assessment.

a) Level of profitability

80. The level of profitability is assessed in the context of the company's industry. We most commonly measure profitability using return on capital (ROC) and EBITDA margins, but we may also use sector-specific ratios. Importantly, as with the other components of competitive position, we review profitability in the context of the industry in which the company operates, not just in its narrower subsector. (See list of industries and subsectors in Appendix B, table 27.)

81. We assess level of profitability on a three-point scale: above average, average, and below average. Industry KCF articles may establish numeric guidance, for instance by stating that an ROC above 12% is considered above average, between 8%-12% is average, and below 8% is below average for the industry, or by differentiating between subsectors in the industry. In the absence of numeric guidance, we compare a company against its peers across the industry.

82. We calculate profitability ratios generally based on a five-year average, consisting of two years of historical data, our projections for the current year (incorporating any reported year-to-date results and estimates for the remainder of the year), and the next two financial years. There may be situations where we consider longer or shorter historical results or forecasts, depending on such factors as availability of financials, transformational events (such as mergers or acquisitions [M&A]), cyclical distortion (such as peak or bottom of the cycle metrics that we do not deem fully representative of the company's level of profitability), and we take into account improving or deteriorating trends in profitability ratios in our assessment.

b) Volatility of profitability

83. We base the volatility of profitability on the standard error of the regression (SER) for a company's historical EBITDA, EBITDA margins, or return on capital. The KCF articles provide guidance on which measures are most appropriate for a given industry or set of companies. For each of these measures, we divide the standard error by the average of that measure over the time period in order to ensure better comparability across companies.

84. The SER is a statistical measure that is an estimate of the deviation around a 'best fit' linear trend line. We regress the company's EBITDA, EBITDA margins, or return on capital against time. A key advantage of SER over standard deviation or coefficient of variation is that it doesn't view upwardly trending data as inherently more volatile. At the same time, we recognize that SER, like any statistical measure, may understate or overstate expected volatility and thus we will make qualitative adjustments where appropriate (see paragraphs 86-90). Furthermore, we only calculate SER when companies have at least seven years of historical annual data and have not significantly changed their line of business during the timeframe, to ensure that the results are meaningful.

85. As with the level of profitability, we evaluate a company's SER in the context of its industry group. For most industries, we establish a six-point scale with 1 capturing the least volatile companies, i.e., those with the lowest SERs, and 6 identifying companies whose profits are most volatile. We have established industry-specific SER parameters using the most recent seven years of data for companies within each sector. We believe that seven years is generally an adequate number of years to capture a business cycle. (See Appendix B, section 4 for industry-specific SER parameters.) For companies whose business segments cross multiple industries, we evaluate the SER in the context of the organization's most dominant industry--if that industry represents at least two-thirds of the organization's EBITDA, sales, or other relevant metric. If the company is a conglomerate and no dominant industry can be identified, we will evaluate its profit volatility in the context of SER guidelines for all nonfinancial companies.

86. In certain circumstances, the SER derived from historical information may understate--or overstate--expected future volatility, and we may adjust the assessment downward or upward. The scope of possible adjustments depends on certain conditions being met as described below.

87. We might adjust the SER-derived volatility assessment to a worse assessment (i.e., to a higher assessment for greater volatility) by up to two categories if the expected level of volatility isn't apparent in historical numbers, and the company either:

- Has a weighted country risk assessment of 4 or worse, which may, notwithstanding past performance, result in a less stable business environment going forward;
- Operates in a subsector of the industry that may be prone to higher technology or regulation changes, or other potential disruptive risks that have not emerged over the seven year period;
- Is of limited size and scope, which will often result in inherently greater vulnerability to external changes; or
- Has pursued material M&A or internal growth projects that obscure the company's underlying performance trend line. As an example, a company may have consummated an acquisition during the trough of the cycle, masking what would otherwise be a significant decline in performance.

88. The choice of one or two categories depends on the degree of likelihood that the related risks will materialize and our view of the likely severity of these risks.

89. Conversely, we may adjust the SER-derived volatility assessment to a better assessment (i.e., to a lower assessment reflecting lower volatility) by up to two categories if we observe that the conditions historically leading to greater volatility have receded and are misrepresentative. This will be the case when:

- The company grew at a moderately faster, albeit more uneven, pace relative to the industry. Since we measure volatility around a linear trend line, a company growing at a constant percentage of moderate increase (relative to the industry) or an uneven pace (e.g., due to "lumpy" capital spending programs) could receive a relatively unfavorable assessment on an unadjusted basis, which would not be reflective of the company's performance in a steady state. (Alternatively, those companies that grow at a significantly higher-than-average industry rate often do so on unsustainable rates of growth or by taking on high-risk strategies. Companies with these high-risk growth strategies would not receive a better assessment and could be adjusted to a worse assessment;)
- The company's geographic, customer, or product diversification has increased in scope as a result of an acquisition or rapid expansion (e.g. large, long-term contracts wins), leading to more stability in future earnings in our view; or
- The company's business model is undergoing material change that we expect will benefit earnings stability, such as a new regulatory framework or major technology shift that is expected to provide a significant competitive hedge and margin protection over time.

90. The choice of one or two categories depends on the degree of likelihood that the related risks will materialize and our view of the likely severity of these risks.

91. If the company either does not have at least seven years of annual data or has materially changed its business lines or undertaken abnormally high levels of M&A during this time period, then we do not use its SER to assess the volatility of profitability. In these cases, we use a proxy to establish the volatility assessment. If there is a peer company that has, and is expected to continue having, very similar profitability volatility characteristics, we use the SER of that peer entity as a proxy.

92. If no such matching peer exists, or one cannot be identified with enough confidence, we perform an assessment of expected volatility based on the following rules:

- An assessment of 3 if we expect the company's profitability, supported by available historical evidence, will exhibit a volatility pattern in line with, or somewhat less volatile than, the industry average.
- An assessment of 2 based on our confidence, supported by available historical evidence, that the company will exhibit lower volatility in profitability metrics than the industry's average. This could be underpinned by some of the factors listed in paragraph 89, whereas those listed in paragraph 87 would typically not apply.
- An assessment of 4 or 5 based on our expectation that profitability metrics will exhibit somewhat higher (4), or meaningfully higher (5) volatility than the industry, supported by available historical evidence, or because of the applicability of possible adjustment factors listed in paragraph 87.
- Assessments of either 1 or 6 are rarely assigned and can only be achieved based on a combination of data evidence and very high confidence tests. For an assessment of 1, we require strong evidence of minimal volatility in profitability metrics compared with the industry, supported by at least five years of historical information, combined with a very high degree of confidence that this will continue in the future, including no country risk, subsector risk or size considerations that could otherwise warrant a worse assessment as per paragraph 87. For an assessment of 6 we require strong evidence of very high volatility in profitability metrics compared with the industry, supported by at least five years of historical information and very high confidence that this will continue in the future.

93. Next, we combine the level of profitability assessment with the volatility assessment to determine the final profitability

assessment using the matrix in Table 15.

Table 15

Profitability Assessment

	--Volatility of profitability assessment--					
Level of profitability assessment	**1**	**2**	**3**	**4**	**5**	**6**
Above average	1	1	2	3	4	5
Average	1	2	3	4	5	6
Below average	2	3	4	5	6	6

5. Combining the preliminary competitive position assessment with profitability

94. The fourth and final step in arriving at a competitive position assessment is to combine the preliminary competitive position assessment with the profitability assessment. We use the combination matrix in Table 16, which shows how the profitability assessment can confirm, strengthen, or weaken (by up to one category) the overall competitive position assessment.

Table 16

Combining The Preliminary Competitive Position Assessment And Profitability Assessment

	--Preliminary competitive position assessment--					
Profitability assessment	**1**	**2**	**3**	**4**	**5**	**6**
1	1	2	2	3	4	5
2	1	2	3	3	4	5
3	2	2	3	4	4	5
4	2	3	3	4	5	5
5	2	3	4	4	5	6
6	2	3	4	5	5	6

95. We generally expect companies with a strong preliminary competitive position assessment to exhibit strong and less volatile profitability metrics. Conversely, companies with a relatively weaker preliminary competitive position assessment will generally have weaker and/or more volatile profitability metrics. Our analysis of profitability helps substantiate whether management is translating any perceived competitive advantages, diversity benefits, and cost management measures into higher earnings and more stable return on capital and return on sales ratios than the averages for the industry. When profitability differs markedly from what the preliminary/anchor competitive position assessment would otherwise imply, we adjust the competitive position assessment accordingly.

96. Our method of adjustment is biased toward the preliminary competitive position assessment rather than toward the profitability assessment (e.g., a preliminary competitive assessment of 6 and a profitability assessment of 1 will result in a final assessment of 5).

E. Cash Flow/Leverage

97. The pattern of cash flow generation, current and future, in relation to cash obligations is often the best indicator of a company's financial risk. The criteria assess a variety of credit ratios, predominately cash flow-based, which

complement each other by focusing on the different levels of a company's cash flow waterfall in relation to its obligations (i.e., before and after working capital investment, before and after capital expenditures, before and after dividends), to develop a thorough perspective. Moreover, the criteria identify the ratios that we think are most relevant to measuring a company's credit risk based on its individual characteristics and its business cycle.

98. For the analysis of companies with intermediate or stronger cash flow/leverage assessments (a measure of the relationship between the company's cash flows and its debt obligations as identified in paragraphs 106 and 124), we primarily evaluate cash flows that reflect the considerable flexibility and discretion over outlays that such companies typically possess. For these entities, the starting point in the analysis is cash flows before working capital changes plus capital investments in relation to the size of a company's debt obligations in order to assess the relative ability of a company to repay its debt. These "leverage" or "payback" cash flow ratios are a measure of how much flexibility and capacity the company has to pay its obligations.

99. For entities with significant or weaker cash flow/leverage assessments (as identified in paragraphs 105 and 124), the criteria also call for an evaluation of cash flows in relation to the carrying cost or interest burden of a company's debt. This will help us assess a company's relative and absolute ability to service its debt. These "coverage"- or "debt service"-based cash flow ratios are a measure of a company's ability to pay obligations from cash earnings and the cushion the company possesses through stress periods. These ratios, particularly interest coverage ratios, become more important the further a company is down the credit spectrum.

1. Assessing cash flow/leverage

100. Under the criteria, we assess cash flow/leverage as 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; or 6, highly leveraged. To arrive at these assessments, the criteria combine the assessments of a variety of credit ratios, predominately 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. For each ratio, there is an indicative cash flow/leverage assessment that corresponds to a specified range of values in one of three given benchmark tables (see tables 17, 18, and 19). We derive the final cash flow/leverage assessment for a company by determining the relevant core ratios, anchoring a preliminary cash flow assessment based on the relevant core ratios, determining the relevant supplemental ratio(s), adjusting the preliminary cash flow assessment according to the relevant supplemental ratio(s), and, finally, modifying the adjusted cash flow/leverage assessment for any material volatility.

2. Core and supplemental ratios

a) Core ratios

101. For each company, we calculate two core credit ratios--funds from operations (FFO) to debt and debt to EBITDA--in accordance with Standard & Poor's ratios and adjustments criteria (see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013). We compare these payback ratios against benchmarks to derive the preliminary cash flow/leverage assessment for a company. These ratios are also useful in determining the relative ranking of the financial risk of companies.

b) Supplemental ratios

102. The criteria also consider one or more supplemental ratios (in addition to the core ratios) to help develop a fuller understanding of a company's financial risk profile and fine-tune our cash flow/leverage analysis. Supplemental ratios

could either confirm or adjust the preliminary cash flow/leverage assessment. The confirmation or adjustment of the preliminary cash flow/leverage assessment will depend on the importance of the supplemental ratios as well as any difference in indicative cash flow/leverage assessment between the core and supplemental ratios as described in section E.3.b.

103. The criteria typically consider five standard supplemental ratios, although the relevant KCF criteria may introduce additional supplemental ratios or focus attention on one or more of the standard supplemental ratios. The standard supplemental ratios include three payback ratios--cash flow from operations (CFO) to debt, free operating cash flow (FOCF) to debt, and discretionary cash flow (DCF) to debt--and two coverage ratios, FFO plus interest to cash interest and EBITDA to interest.

104. The criteria provide guidelines as to the relative importance of certain ratios if a company exhibits characteristics such as high leverage, working capital intensity, capital intensity, or high growth.

105. If the preliminary cash flow/leverage assessment is significant or weaker (see section E.3), then two coverage ratios, FFO plus interest to cash interest and EBITDA to interest, will be given greater importance as supplemental ratios. For the purposes of calculating the coverage ratios, "cash interest" includes only cash interest payments (i.e., interest excludes noncash interest payable on, for example, payment-in-kind [PIK] instruments) and does not include any Standard & Poor's adjusted interest on such items as leases, while "interest" is the income statement figure plus Standard & Poor's adjustments to interest (see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013).

106. If the preliminary cash flow/leverage assessment is intermediate or stronger, the criteria first apply the three standard supplemental ratios of CFO to debt, FOCF to debt, and DCF to debt. When FOCF to debt and DCF to debt indicate a cash flow/leverage assessment that is lower than the other payback-ratio-derived cash flow/leverage assessments, it signals that the company has either larger than average capital spending or other non-operating cash distributions (including dividends). If these differences persist and are consistent with a negative trend in overall ratio levels, which we believe is not temporary, then these supplemental leverage ratios will take on more importance in the analysis.

107. If the supplemental ratios indicate a cash flow/leverage assessment that is different than the preliminary cash flow/leverage assessment, it could suggest an unusual debt service or fixed charge burden, working capital or capital expenditure profile, or unusual financial activity or policies. In such cases, we assess the sustainability or persistence of these differences. For example, if either working capital or capital expenditures are unusually low, leading to better indicated assessments, we examine the sustainability of such lower spending in the context of its impact on the company's longer term competitive position. If there is a deteriorating trend in the company's asset base, we give these supplemental ratios less weight. If either working capital or capital expenditures are unusually high, leading to weaker indicated assessments, we examine the persistence and need for such higher spending. If elevated spending levels are required to maintain a company's competitive position, for example to maintain the company's asset base, we give more weight to these supplemental ratios.

108. For capital-intensive companies, EBITDA and FFO may overstate financial strength, whereas FOCF may be a more accurate reflection of their cash flow in relation to their financial obligations. The criteria generally consider a

capital-intensive company as having ongoing capital spending to sales of greater than 10%, or depreciation to sales of greater than 8%. For these companies, the criteria place more weight on the supplementary ratio of FOCF to debt. Where we place more analytic weight on FOCF to debt, we also seek to estimate the amount of maintenance or full cycle capital required (see Appendix C) under normal conditions (we estimate maintenance or full-cycle capital expenditure required because this is not a reported number). The FOCF figure may be adjusted by adding back estimated discretionary capital expenditures. The adjusted FOCF to debt based on maintenance or full cycle capital expenditures often helps determine how much importance to place on this ratio. If both the FOCF to debt and the adjusted (for estimated discretionary capital spending) FOCF to debt derived assessments are different from the preliminary cash/flow leverage assessment, then these supplemental leverage ratios take on more importance in the analysis.

109. For working-capital-intensive companies, EBITDA and FFO may also overstate financial strength, and CFO may be a more accurate measure of the company's cash flow in relation to its financial risk profile. Under the criteria, if a company has a working capital-to-sales ratio that exceeds 25% or if there are significant seasonal swings in working capital, we generally consider it to be working-capital-intensive. For these companies, the criteria place more emphasis on the supplementary ratio of CFO to debt. Examples of companies that have working-capital-intensive characteristics can be found in the capital goods, metals and mining downstream, or the retail and restaurants industries. The need for working capital in those industries reduces financial flexibility and, therefore, these supplemental leverage ratios take on more importance in the analysis.

110. For all companies, when FOCF to debt or DCF to debt is negative or indicates materially lower cash flow/leverage assessments, the criteria call for an examination of management's capital spending and cash distribution strategies. For high-growth companies, typically the focus is on FFO to debt instead of FOCF to debt because the latter ratio can vary greatly depending on the growth investment the company is undergoing. The criteria generally consider a high-growth company one that exhibits real revenue growth in excess of 8% per year. Real revenue growth excludes price or foreign exchange related growth, under these criteria. In cases where FOCF or DCF is low, there is a greater emphasis on monitoring the sustainability of margins and return on capital and the overall financing mix to assess the likely trend of future debt ratios. In addition, debt service ratio analysis will be important in such situations. For companies with more moderate growth, the focus is typically on FOCF to debt unless the capital spending is short term or is not funded with debt.

111. For companies that have ongoing and well entrenched banking relationships we can reflect these relationships in our cash flow/leverage analysis through the use of the interest coverage ratios as supplemental ratios. These companies generally have historical links and a strong ongoing relationship with their main banks, as well as shareholdings by the main banks, and management influence and interaction between the main banks and the company. Based on their bank relationships, these companies often have lower interest servicing costs than peers, even if the macro economy worsens. In such cases, we generally use the interest coverage ratios as supplemental ratios. This type of banking relationship occurs in Japan, for example, where companies that have the type of bank relationship described in this paragraph tend to have a high socioeconomic influence within their country by way of their revenue size, total debt quantum, number of employees, and the relative importance of the industry.

c) Time horizon and ratio calculation

112. A company's credit ratios may vary, often materially, over time due to economic, competitive, technological, or investment cycles, the life stage of the company, and corporate or strategic actions. Thus, we evaluate credit ratios on a time series basis with a clear forward-looking bias. The length of the time series is dependent on the relative credit risk of the company and other qualitative factors and the weighting of the time series varies according to transformational events. A transformational event is any event that could cause a material change in a company's financial profile, whether caused by changes to the company's capital base, capital structure, earnings, cash flow profile, or financial policies. Transformational events can include mergers, acquisitions, divestitures, management changes, structural changes to the industry or competitive environment, and/or product development and capital programs. This section provides guidance on the timeframe and weightings the criteria apply to calculate the indicative ratios.

113. The criteria generally consider the company's credit ratios for the previous one to two years, current-year forecast, and the two subsequent forecasted financial years. There may be situations where longer--or even shorter--historical results or forecasts are appropriate, depending on such factors as availability of financials, transformational events, or relevance. For example, a utility company with a long-term capital spending program may lend itself to a longer-term forecast, whereas for a company experiencing a near-term liquidity squeeze even a two-year forecast will have limited value. Alternatively, for most commodities-based companies we emphasize credit ratios based on our forward-looking view of market conditions, which may differ materially from the historical period.

114. Historical patterns in cash flow ratios are informative, particularly in understanding past volatility, capital spending, growth, accounting policies, financial policies, and business trends. Our analysis starts with a review of these historical patterns in order to assess future expected credit quality. Historical patterns can also provide an indication of potential future volatility in ratios, including that which results from seasonality or cyclicality. A history of volatility could result in a more conservative assessment of future cash flow generation if we believe cash flow will continue to be volatile.

115. The forecast ratios are based on an expected base-case scenario developed by Standard & Poor's, incorporating current and near-term economic conditions, industry assumptions, and financial policies. The prospective cyclical and longer-term volatility associated with the industry in which the issuer operates is addressed in the industry risk criteria (see section B) and the longer-term directional influence or event risk of financial policies is addressed in our financial policy criteria (see section H).

116. The criteria generally place greater emphasis on forecasted years than historical years in the time series of credit ratios when calculating the indicative credit ratio. For companies where we have five years of ratios as described in section E.3, generally we calculate the indicative ratio by weighting the previous two years, the current year, and the forecasted two years as 10%, 15%, 25%, 25%, and 25%, respectively.

117. This weighting changes, however, to place even greater emphasis on the current and forecast years when:

- The issuer meets the characteristics described in paragraph 113, and either shorter- or longer-term forecasts are applicable. The weights applied will generally be quite forward weighted, particularly if a company is undergoing a transformational event and there is moderate or better cash flow certainty.
- The issuer is forecast to generate negative cash flow available for debt repayment, which we believe could lead to

deteriorating credit metrics. Forecast negative cash flows could be generated from operating activities as well as capital expenditures, share buybacks, dividends, or acquisitions, as we forecast these uses of cash based on the company's track record, market conditions, or financial policy. The weights applied will generally be 30%, 40%, and 30% for the current and two subsequent years, respectively.

- The issuer is in an industry that is prospectively volatile or that has a high degree of cash flow uncertainty. Industries that are prospectively volatile are industries whose competitive risk and growth assessments are either high risk (5) or very high risk (6) or whose overall industry risk assessments are either high risk (5) or very high risk (6). The weights applied will generally be 50% for the current year and 50% for the first subsequent forecast year.

118. When the indicative ratio(s) is borderline (i.e., less than 10% different from the threshold in relative terms) between two assessment thresholds (as described in section E.3 and tables 17, 18, and 19) and the forecast points to a switch in the ratio between categories during the rating timeframe, we will weigh the forecast even more heavily in order to prospectively capture the trend.

119. For companies undergoing a transformational event, the weighting of the time series could vary significantly.

120. For companies undergoing a transformational event and with significant or weaker cash flow/leverage assessments, we place greater weight on near-term risk factors. That's because overemphasis on longer-term (inherently less predictable) issues could lead to some distortion when assessing the risk level of a speculative-grade company. We generally analyze a company using the arithmetic mean of the credit ratios expected according to our forecasts for the current year (or pro forma current year) and the subsequent financial year. A common example of this is when a private equity firm acquires a company using additional debt leverage, which makes historical financial ratios meaningless. In this scenario, we weight or focus the majority of our analysis on the next one or two years of projected credit measures.

3. Determining the cash flow/leverage assessment
a) Identifying the benchmark table

121. Tables 17, 18, and 19 provide 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.

122. If an industry exhibits low volatility, the threshold levels for the applicable ratios to achieve a given cash flow/leverage assessment are less stringent than those in the medial or standard volatility tables, although the range of the ratios is narrower. Conversely, if an industry exhibits medial or standard levels of volatility, the threshold for the applicable ratios to achieve a given cash flow/leverage assessment are elevated, albeit with a wider range of values.

123. The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA (see section A, table 1). The low volatility table (table 19) will generally apply when a company's CICRA is 1, unless otherwise indicated in a sector's KCF criteria. The medial volatility table (table 18) will be used under certain circumstances for companies with a CICRA of 1 or 2. Those circumstances are described in the respective sectors' KCF criteria. The standard volatility table (table 17) serves as the relevant benchmark table for companies with a CICRA of 2 or worse, and we will always use it for companies with a CICRA of 1 or 2 and whose competitive position is assessed 5 or 6. Although infrequent, we will use the low volatility table when

a company's CICRA is 2 for companies that exhibit or are expected to exhibit low levels of volatility. The choice of volatility tables for companies with a CICRA of 2 is addressed in the respective sector's KCF article.

Table 17

Cash Flow/Leverage Analysis Ratios--Standard Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	**Debt/EBITDA (x)**	**FFO/cash interest(x)**	**EBITDA/interest (x)**	**CFO/debt (%)**	**FOCF/debt (%)**	**DCF/debt (%)**
Minimal	60+	Less than 1.5	More than 13	More than 15	More than 50	40+	25+
Modest	45-60	1.5-2	9-13	10-15	35-50	25-40	15-25
Intermediate	30-45	2-3	6-9	6-10	25-35	15-25	10-15
Significant	20-30	3-4	4-6	3-6	15-25	10-15	5-10
Aggressive	12-20	4-5	2-4	2-3	10-15	5-10	2-5
Highly leveraged	Less than 12	Greater than 5	Less than 2	Less than 2	Less than 10	Less than 5	Less than 2

Table 18

Cash Flow/Leverage Analysis Ratios--Medial Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	**Debt/EBITDA (x)**	**FFO/cash interest (x)**	**EBITDA/interest (x)**	**CFO/debt (%)**	**FOCF/debt (%)**	**DCF/debt (%)**
Minimal	50+	less than 1.75	10.5+	14+	40+	30+	18+
Modest	35-50	1.75-2.5	7.5-10.5	9-14	27.5-40	17.5-30	11-18
Intermediate	23-35	2.5-3.5	5-7.5	5-9	18.5-27.5	9.5-17.5	6.5-11
Significant	13-23	3.5-4.5	3-5	2.75-5	10.5-18.5	5-9.5	2.5-6.5
Aggressive	9-13	4.5-5.5	1.75-3	1.75-2.75	7-10.5	0-5	(11)-2.5
Highly leveraged	Less than 9	Greater than 5.5	Less than 1.75	Less than 1.75	Less than 7	Less than 0	Less than (11)

Table 19

Cash Flow/Leverage Analysis Ratios--Low Volatility

	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	**Debt/EBITDA (x)**	**FFO/cash interest (x)**	**EBITDA/interest (x)**	**CFO/debt (%)**	**FOCF/debt (%)**	**DCF/debt (%)**
Minimal	35+	Less than 2	More than 8	More than 13	More than 30	20+	11+
Modest	23-35	2-3	5-8	7-13	20-30	10-20	7-11
Intermediate	13-23	3-4	3-5	4-7	12-20	4-10	3-7
Significant	9-13	4-5	2-3	2.5-4	8-12	0-4	0-3
Aggressive	6-9	5-6	1.5-2	1.5-2.5	5-8	(10)-0	(20)-0
Highly leveraged	Less than 6	Greater than 6	Less than 1.5	Less than 1.5	Less than 5	Less than (10)	Less than (20)

b) Aggregating the credit ratio assessments

124. To determine the final cash flow/leverage assessment, we make these calculations:
1) First, calculate a time series of standard core and supplemental credit ratios, select the relevant benchmark table, and determine the appropriate time weighting of the credit ratios.

- Calculate the two standard core credit ratios and the five standard supplemental credit ratios over a five-year time horizon.
- Consult the relevant industry KCF article (if applicable), which may identify additional supplemental ratio(s). The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA.
- Calculate the appropriate weighted average cash flow/leverage ratios. If the company is undergoing a transformational event, then the core and supplemental ratios will typically be calculated based on Standard & Poor's projections for the current and next one or two financial years.

2) Second, we use the core ratios to determine the preliminary cash flow assessment.

- Compare the core ratios (FFO to debt and debt to EBITDA) to the ratio ranges in the relevant benchmark table.
- If the core ratios result in different cash flow/leverage assessments, we will select the relevant core ratio based on which provides the best indicator of a company's future leverage.

3) Third, we review the supplemental ratio(s).

- Determine the importance of standard or KCF supplemental ratios based on company-specific characteristics, namely, leverage, capital intensity, working capital intensity, growth rate, or industry.

4) Fourth, we calculate the adjusted cash flow/leverage assessment.

- If the cash flow/leverage assessment(s) indicated by the important supplemental ratio(s) differs from the preliminary cash flow/leverage assessment, we might adjust the preliminary cash flow/leverage assessment by one category in the direction of the cash flow/leverage assessment indicated by the supplemental ratio(s) to derive the adjusted cash flow/leverage assessment. We will make this adjustment if, in our view, the supplemental ratio provides the best indicator of a company's future leverage.
- If there is more than one important supplemental ratio and they result in different directional deviations from the preliminary cash flow/leverage assessment, we will select one as the relevant supplemental ratio based on which, in our opinion, provides the best indicator of a company's future leverage. We will then make the adjustment outlined above if the selected supplemental ratio differs from the preliminary cash flow/leverage assessment and the selected supplemental ratio provides the best overall indicator of a company's future leverage.

5) Lastly, we determine the final cash flow/leverage assessment based on the volatility adjustment.

- We classify companies as stable for these cash flow criteria if cash flow/leverage ratios are expected to move up by one category during periods of stress based on their business risk profile. The final cash flow/leverage assessment for these companies will not be modified from the adjusted cash flow/leverage assessment.
- We classify companies as volatile for these cash flow criteria if cash flow/leverage ratios are expected to move one or two categories worse during periods of stress based on their business risk profiles. Typically, this is equivalent to EBITDA declining about 30% from its current level. The final cash flow/leverage assessment for these companies will be modified to one category weaker than the adjusted cash flow/leverage assessment; the adjustment will be eliminated if cash flow/leverage ratios, as evaluated, include a moderate to high level of stress already.
- We classify companies as highly volatile for these cash flow criteria if cash flow/leverage ratios are expected to move two or three categories worse during periods of stress, based on their business risk profiles. Typically, this is equivalent to EBITDA declining about 50% from its current level. The final cash flow/leverage assessment for these companies will be modified to two categories weaker than the adjusted cash flow/leverage assessment; the adjustment will be eliminated or reduced to one category if cash flow/leverage ratios, as evaluated, include a moderate to high level of stress already.

125. The volatility adjustment is the mechanism by which we factor a "cushion" of medium-term variance to current financial performance not otherwise captured in either the near-term base-case forecast or the long-term business risk

assessment. We make this adjustment based on the following:

- The expectation of any potential cash flow/leverage ratio movement is both prospective and dependent on the current business or economic conditions.
- Stress scenarios include, but are not limited to, a recessionary economic environment, technology or competitive shifts, loss or renegotiation of major contracts or customers, and key product or input price movements, as typically defined in the company's industry risk profile and competitive position assessment.
- The volatility adjustment is not static and is company specific. At the bottom of an economic cycle or during periods of stressed business conditions, already reflected in the general industry risk or specific competitive risk profile, the prospect of weakening ratios is far less than at the peak of an economic cycle or business conditions.
- The expectation of prospective ratio changes may be formed by observed historical performance over an economic, business, or product cycle by the company or by peers.
- The assessment of which classification to use when evaluating the prospective number of scoring category moves will be guided by how close the current ratios are to the transition point (i.e. "buffer" in the current scoring category) and the corresponding amount of EBITDA movement at each scoring transition.

F. Diversification/Portfolio Effect

126. Under the criteria, diversification/portfolio effect applies to companies that we regard as conglomerates. They are companies that have multiple core business lines that may be operated as separate legal entities. For the purpose of these criteria, a conglomerate would have at least three business lines, each contributing a material source of earnings and cash flow.

127. The criteria aim to measure how diversification or the portfolio effect could improve the anchor of a company with multiple business lines. This approach helps us determine how the credit strength of a corporate entity with a given mix of business lines could improve based on its diversity. The competitive position factor assesses the benefits of diversity within individual lines of business. This factor also assesses how poorly performing businesses within a conglomerate affect the organization's overall business risk profile.

128. Diversification/portfolio effect could modify the anchor depending on how meaningful we think the diversification is, and on the degree of correlation we find in each business line's sensitivity to economic cycles. This assessment will have either a positive or neutral impact on the anchor. We capture any potential factor that weakens a company's diversification, including poor management, in our management and governance assessment.

129. We define a conglomerate as a diversified company that is involved in several industry sectors. Usually the smallest of at least three distinct business segments/lines would contribute at least 10% of either EBITDA or FOCF and the largest would contribute no more than 50% of EBITDA or FOCF, with the long-term aim of increasing shareholder value by generating cash flow. Industrial conglomerates usually hold a controlling stake in their core businesses, have highly identifiable holdings, are deeply involved in the strategy and management of their operating companies, generally do not frequently roll over or reshuffle their holdings by buying and selling companies, and therefore have high long-term exposure to the operating risks of their subsidiaries.

130. In rating a conglomerate, we first assess management's commitment to maintain the diversified portfolio over a

longer-term horizon. These criteria apply only if the company falls within our definition of a conglomerate.

1. Assessing diversification/portfolio effect

131. A conglomerate's diversification/portfolio effect is assessed as 1, significant diversification; 2, moderate diversification; or 3, neutral. An assessment of moderate diversification or significant diversification potentially raises the issuer's anchor. To achieve an assessment of significant diversification, an issuer should have uncorrelated diversified businesses whose breadth is among the most comprehensive of all conglomerates'. This assessment indicates that we expect the conglomerate's earnings volatility to be much lower through an economic cycle than an undiversified company's. To achieve an assessment of moderate diversification, an issuer typically has a range of uncorrelated diversified businesses that provide meaningful benefits of diversification with the expectation of lower earnings volatility through an economic cycle than an undiversified company's.

132. We expect that a conglomerate will also benefit from diversification if its core assets consistently produce positive cash flows over our rating horizon. This supports our assertion that the company diversifies to take advantage of allocating capital among its business lines. To this end, our analysis focuses on a conglomerate's track record of successfully deploying positive discretionary cash flow into new business lines or expanding capital-hungry business lines. We assess companies that we do not expect to achieve these benefits as neutral.

2. Components of correlation and how it is incorporated into our analysis

133. We determine the assessment for this factor based on the number of business lines in separate industries (as described in table 27) and the degree of correlation between these business lines as described in table 20. There is no rating uplift for an issuer with a small number of business lines that are highly correlated. By contrast, a larger number of business lines that are not closely correlated provide the maximum rating uplift.

Table 20

Assessing Diversification/Portfolio Effect

	--Number of business lines--		
Degree of correlation of business lines	**3**	**4**	**5 or more**
High	Neutral	Neutral	Neutral
Medium	Neutral	Moderately diversified	Moderately diversified
Low	Moderately diversified	Significantly diversified	Significantly diversified

134. The degree of correlation of business lines is high if the business lines operate within the same industry, as defined by the industry designations in Appendix B, table 27. The degree of correlation of business lines is medium if the business lines operate within different industries, but operate within the same geographic region (for further guidance on defining geographic regions, see Appendix A, table 26). An issuer has a low degree of correlation across its business lines if these business lines are both a) in different industries and b) either operate in different regions or operate in multiple regions.

135. If we believe that a conglomerate's various industry exposures fail to provide a partial hedge against the consolidated entity's volatility because they are highly correlated through an economic cycle, then we assess the diversification/portfolio effect as neutral.

G. Capital Structure

136. Standard & Poor's uses its capital structure criteria to assess risks in a company's capital structure that may not show up in our standard analysis of cash flow/leverage. These risks may exist as a result of maturity date or currency mismatches between a company's sources of financing and its assets or cash flows. These can be compounded by outside risks, such as volatile interest rates or currency exchange rates.

1. Assessing capital structure

137. Capital structure is a modifier category, which adjusts the initial anchor for a company after any modification due to diversification/portfolio effect. We assess a number of subfactors to determine the capital structure assessment, which can then raise or lower the initial anchor by one or more notches--or have no effect in some cases. We assess capital structure as 1, very positive; 2, positive; 3, neutral; 4, negative; or 5, very negative. In the large majority of cases, we believe that a firm's capital structure will be assessed as neutral. To assess a company's capital structure, we analyze four subfactors:

- Currency risk associated with debt,
- Debt maturity profile (or schedule),
- Interest rate risk associated with debt, and
- Investments.

138. Any of these subfactors can influence a firm's capital structure assessment, although some carry greater weight than others, based on a tiered approach:

- Tier one risk subfactors: Currency risk of debt and debt maturity profile, and
- Tier two risk subfactor: Interest rate risk of debt.

139. The initial capital structure assessment is based on the first three subfactors (see table 21). We may then adjust the preliminary assessment based on our assessment of the fourth subfactor, investments.

Table 21

Preliminary Capital Structure Assessment

Preliminary capital structure assessment	Subfactor assessments
Neutral	No tier one subfactor is negative.
Negative	One tier one subfactor is negative, and the tier two subfactor is neutral.
Very negative	Both tier one subfactors are negative, or one tier one subfactor is negative and the tier two subfactor is negative.

140. Tier one subfactors carry the greatest risks, in our view, and, thus, could have a significant impact on the capital structure assessment. This is because, in our opinion, these factors have a greater likelihood of affecting credit metrics and potentially causing liquidity and refinancing risk. The tier two subfactor is important in and of itself, but typically less so than the tier one subfactors. In our view, in the majority of cases, the tier two subfactor in isolation has a lower likelihood of leading to liquidity and default risk than do tier one subfactors.

141. The fourth subfactor, investments, as defined in paragraph 153, quantifies the impact of a company's investments on

its overall financial risk profile. Although not directly related to a firm's capital structure decisions, certain investments could provide a degree of asset protection and potential financial flexibility if they are monetized. Thus, the fourth subfactor could modify the preliminary capital structure assessment (see table 22). If the subfactor is assessed as neutral, then the preliminary capital structure assessment will stand. If investments is assessed as positive or very positive, we adjust the preliminary capital structure assessment upward (as per table 22) to arrive at the final assessment.

Table 22

Final Capital Structure Assessment

	--Investments subfactor assessment--		
Preliminary capital structure assessment	**Neutral**	**Positive**	**Very positive**
Neutral	Neutral	Positive	Very positive
Negative	Negative	Neutral	Positive
Very negative	Very negative	Negative	Negative

2. Capital structure analysis: Assessing the subfactors

a) Subfactor 1: Currency risk of debt

142. Currency risk arises when a company borrows without hedging in a currency other than the currency in which it generates revenues. Such an unhedged position makes the company potentially vulnerable to fluctuations in the exchange rate between the two currencies, in the absence of mitigating factors. We determine the materiality of any mismatch by identifying situations where adverse exchange-rate movements could weaken cash flow and/or leverage ratios. We do not include currency mismatches under the following scenarios:

- The country where a company generates its cash flows has its currency pegged to the currency in which the company has borrowed, or vice versa (or the currency of cash flows has a strong track record and government policy of stability with the currency of borrowings), examples being the Hong Kong dollar which is pegged to the U.S. dollar, and the Chinese renminbi which is managed in a narrow band to the U.S. dollar (and China's foreign currency reserves are mainly in U.S. dollars). Moreover, we expect such a scenario to continue for the foreseeable future;
- A company has the proven ability, through regulation or contract, to pass through changes in debt servicing costs to its customers; or
- A company has a natural hedge, such as where it may sell its product in a foreign currency and has matched its debt in that same currency.

143. We also recognize that even if an entity generates insufficient same-currency cash flow to meet foreign currency-denominated debt obligations, it could have substantial other currency cash flows it can convert to meet these obligations. Therefore, the relative amount of foreign denominated debt as a proportion of total debt is an important factor in our analysis. If foreign denominated debt, excluding fully hedged debt principal, is 15% or less of total debt, we assess the company as neutral on currency risk of debt. If foreign-denominated debt, excluding fully hedged debt principal, is greater than 15% of total debt, and debt to EBITDA is greater than 3.0x, we evaluate currency risks through further analysis.

144. If an entity's foreign-denominated debt in a particular currency represents more than 15% of total debt, and if its debt to EBITDA ratio is greater than 3.0x, we identify whether a currency-specific interest coverage ratio indicates potential

currency risk. The coverage ratio divides forecasted operating cash flow in each currency by interest payments over the coming 12 months for that same currency. It is often easier to ascertain the geographic breakdown of EBITDA as opposed to operating cash flow. So in situations where we don't have sufficient cash flow information, we may calculate an EBITDA to interest expense coverage ratio in the relevant currencies. If neither cash flow nor EBITDA information is disclosed, we estimate the relevant exposures based on available information.

145. In such an instance, our assessment of this subfactor is negative if we believe any appropriate interest coverage ratio will fall below 1.2x over the next 12 months.

b) Subfactor 2: Debt maturity profile

146. A firm's debt maturity profile shows when its debt needs to be repaid, or refinanced if possible, and helps determine the firm's refinancing risk. Lengthier and more evenly spread out debt maturity schedules reduce refinancing risk, compared with front-ended and compressed ones, since the former give an entity more time to manage business- or financial market-related setbacks.

147. In evaluating debt maturity profiles, we measure the weighted average maturity (WAM) of bank debt and debt securities (including hybrid debt) within a capital structure, and make simplifying assumptions that debt maturing beyond year five matures in year six. WAM = (Maturity1/Total Debt)*tenor1 + (Maturity2/Total Debt)* tenor2 +... (Thereafter/Total Debt)* tenor6

148. In evaluating refinancing risk, we consider risks in addition to those captured under the 12-month to 24-month time-horizons factored in our liquidity criteria (see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013). While we recognize that investment-grade companies may have more certain future business prospects and greater access to capital than speculative-grade companies, all else being equal, we view a company with a shorter maturity schedule as having greater refinancing risk compared to a company with a longer one. In all cases, we assess a company's debt maturity profile in conjunction with its liquidity and potential funding availability. Thus, a short-dated maturity schedule alone is not a negative if we believe the company can maintain enough liquidity to pay off debt that comes due in the near term.

149. Our assessment of this subfactor is negative if the WAM is two years or less, and the amount of these near-term maturities is material in relation to the issuer's liquidity so that under our base-case forecast, we believe the company's liquidity assessment will become less than adequate or weak over the next two years due to these maturities. In certain cases, we may assess a debt maturity profile as negative regardless of whether or not the company passes the aforementioned test. We expect such instances to be rare, and will include scenarios where we believed a concentration of debt maturities within a five-year time horizon poses meaningful refinancing risk, either due to the size of the maturities in relation to the company's liquidity sources, the company's leverage profile, its operating trends, lender relationships, and/or credit market standings.

c) Subfactor 3: Interest rate risk of debt

150. The interest rate risk of debt subfactor analyzes the company's mix of fixed-rate and floating-rate debt. Generally, a higher proportion of fixed-rate debt leads to greater predictability and stability of interest expense and therefore cash flows. The exception would be companies whose operating cash flows are to some degree correlated with interest rate movements--for example, a regulated utility whose revenues are indexed to inflation--given the typical correlation

between nominal interest rates and inflation.

151. The mix of fixed versus floating-rate debt is usually not a significant risk factor for companies with intermediate or better financial profiles, strong profitability, and high interest coverage. In addition, the interest rate environment at a given point in time will play a role in determining the impact of interest rate movements. Our assessment of this subcategory will be negative if a 25% upward shift (e.g., from 2.0% to 2.5%) or a 100 basis-point upward shift (e.g., 2% to 3%) in the base interest rate of the floating rate debt will result in a breach of interest coverage covenants or interest coverage rating thresholds identified in the cash flow/leverage criteria (see section E.3).

152. Many loan agreements for speculative-grade companies contain a clause requiring a percentage of floating-rate debt to be hedged for a period of two to three years to mitigate this risk. However, in many cases the loan matures after the hedge expires, creating a mismatched hedge. We consider only loans with hedges that match the life of the loan to be--effectively--fixed-rate debt.

d) Subfactor 4: Investments

153. For the purposes of the criteria, investments refer to investments in unconsolidated equity affiliates, other assets where the realizable value isn't currently reflected in the cash flows generated from those assets (e.g. underutilized real-estate property), we do not expect any additional investment or support to be provided to the affiliate, and the investment is not included within Standard & Poor's consolidation scope and so is not incorporated in the company's business and financial risk profile analysis. If equity affiliate companies are consolidated, then the financial benefits and costs of these investments will be captured in our cash flow and leverage analysis. Similarly, where the company's ownership stake does not qualify for consolidation under accounting rules, we may choose to consolidate on a pro rata basis if we believe that the equity affiliates' operating and financing strategy is influenced by the rated entity. If equity investments are strategic and provide the company with a competitive advantage, or benefit a company's scale, scope, and diversity, these factors will be captured in our competitive position criteria and will not be used to assess the subfactor investments as positive. Within the capital structure criteria, we aim to assess nonstrategic financial investments that could provide a degree of asset protection and financial flexibility in the event they are monetized. These investments must be noncore and separable, meaning that a potential divestiture, in our view, has no impact on the company's existing operations.

154. In many instances, the cash flows generated by an equity affiliate, or the proportional share of the associate company's net income, might not accurately reflect the asset's value. This could occur if the equity affiliate is in high growth mode and is currently generating minimal cash flow or net losses. This could also be true of a physical asset, such as real estate. From a valuation standpoint, we recognize the subjective nature of this analysis and the potential for information gaps. As a result, in the absence of a market valuation or a market valuation of comparable companies in the case of minority interests in private entities, we will not ascribe value to these assets.

155. We assess this subfactor as positive or very positive if three key characteristics are met. First, an estimated value can be ascribed to these investments based on the presence of an existing market value for the firm or comparable firms in the same industry. Second, there is strong evidence that the investment can be monetized over an intermediate timeframe--in the case of an equity investment, our opinion of the marketability of the investment would be enhanced by the presence of an existing market value for the firm or comparable firms, as well as our view of market liquidity.

Third, monetization of the investment, assuming proceeds would be used to repay debt, would be material enough to positively move existing cash flow and leverage ratios by at least one category and our view on the company's financial policy, specifically related to financial discipline, supports the assessment that the potential proceeds would be used to pay down debt. This subfactor is assessed as positive if debt repayment from the investment sale has the potential to improve cash flow and leverage ratios by one category. We assess investments as very positive if proceeds upon sale of the investment have the potential to improve cash flow and leverage ratios by two or more categories. If the three characteristics are not met, this subfactor will be assessed as neutral and the preliminary capital structure assessment will stand.

156. We will not assess the investments subfactor as positive or very positive when the anchor is 'b+' or lower unless the three conditions described in paragraph 155 are met, and:

- For issuers with less than adequate or weak liquidity, the company has provided a credible near-term plan to sell the investment.
- For issuers with adequate or better liquidity, we believe that the company, if needed, could sell the investment in a relatively short timeframe.

H. Financial Policy

157. Financial policy refines the view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage assessment (see section E). Those assumptions do not always reflect or entirely capture the short-to-medium term event risks or the longer-term risks stemming from a company's financial policy. To the extent movements in one of these factors cannot be confidently predicted within our forward-looking evaluation, we capture that risk within our evaluation of financial policy. The cash flow/leverage assessment will typically factor in operating and cash flows metrics we observed during the past two years and the trends we expect to see for the coming two years based on operating assumptions and predictable financial policy elements, such as ordinary dividend payments or recurring acquisition spending. However, over that period and, generally, over a longer time horizon, the firm's financial policies can change its financial risk profile based on management's or, if applicable, the company's controlling shareholder's (see Appendix E, paragraphs 254-257) appetite for incremental risk or, conversely, plans to reduce leverage. We assess financial policy as 1) positive, 2) neutral, 3) negative, or as being owned by a financial sponsor. We further identify financial sponsor-owned companies as "FS-4", "FS-5", "FS-6", or "FS-6 (minus)" (see section H.2).

1. Assessing financial policy

158. First, we determine if a company is owned by a financial sponsor. Given the intrinsic characteristics and aggressive nature of financial sponsor's strategies (i.e. short- to intermediate-term holding periods and the use of debt or debt-like instruments to maximize shareholder returns), we assign a financial risk profile assessment to a firm controlled by a financial sponsor that reflects the likely impact on leverage due to these strategies and we do not separately analyze management's financial discipline or financial policy framework.

159. If a company is not controlled by a financial sponsor, we evaluate management's financial discipline and financial policy framework. Management's financial discipline measures its tolerance for incremental financial risk or,

conversely, its willingness to maintain the same degree of financial risk or to lower it compared with recent cash flow/leverage metrics and our projected ratios for the next two years. The company's financial policy framework assesses the comprehensiveness, transparency, and sustainability of the entity's financial policies. We do not assess these factors for financial sponsor controlled firms.

160. The financial discipline assessments can have a positive or negative influence on an enterprise's overall financial policy assessment, or can have no net effect. Conversely, the financial policy framework assessment cannot positively influence the overall financial policy assessment. It can constrain the overall financial policy assessment to no greater than neutral.

161. The separate assessments of a company's financial policy framework and financial discipline determine the financial policy adjustment.

162. We assess management's financial discipline as 1, positive; 2, neutral; or 3, negative. We determine the assessment by evaluating the predictability of an entity's expansion plans and shareholder return strategies. We take into account, generally, management's tolerance for material and unexpected negative changes in credit ratios or, instead, its plans to rapidly decrease leverage and keep credit ratios within stated boundaries.

163. A company's financial policy framework assessment is: 1, supportive or 2, non-supportive. We make the determination by assessing the comprehensiveness of a company's financial policy framework and whether financial targets are clearly communicated to a large number of stakeholders, and are well defined, achievable, and sustainable.

Table 23

Financial Policy Assessments

Assessment	What it means	Guidance
Positive	Indicates that we expect management's financial policy decisions to have a positive impact on credit ratios over the time horizon, beyond what can be reasonably built in our forecasts on the basis of normalized operating and cash flow assumptions. An example would be when a credible management team commits to dispose of assets or raise equity over the short to medium term in order to reduce leverage. A company with a 1 financial risk profile will not be assigned a positive assessment.	If financial discipline is positive, and the financial policy framework is supportive
Neutral	Indicates that, in our opinion, future credit ratios won't differ materially over the time horizon beyond what we have projected, based on our assessment of management's financial policy, recent track record, and operating forecasts for the company. A neutral financial policy assessment effectively reflects a low probability of "event risk," in our view.	If financial discipline is positive, and the financial policy framework is non-supportive. Or when financial discipline is neutral, regardless of the financial policy framework assessment.
Negative	Indicates our view of a lower degree of predictability in credit ratios, beyond what can be reasonably built in our forecasts, as a result of management's financial discipline (or lack of it). It points to high event risk that management's financial policy decisions may depress credit metrics over the time horizon, compared with what we have already built in our forecasts based on normalized operating and cash flow assumptions.	If financial discipline is negative, regardless of the financial policy framework assessment
Financial Sponsor*	We define a financial sponsor as an entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short to intermediate time frame. Accordingly, the financial risk profile we assign to companies that are controlled by financial sponsors ordinarily reflects our presumption of some deterioration in credit quality in the medium term. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.	We define financial sponsor-owned companies as companies that are owned 40% or more by a financial sponsor or a group of three or less financial sponsors and where we consider that the sponsor(s) exercise control of the company solely or together.

*Assessed as FS-4, FS-5, FS-6, or FS-6 (minus).

2. Financial sponsor-controlled companies

164. We define a financial sponsor as an entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short-to-intermediate time frame. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.

165. We define financial sponsor-owned companies as companies that are owned 40% or more by a financial sponsor or a group of three or less financial sponsors and where we consider that the sponsor(s) exercise control of the company solely or together.

166. We differentiate between financial sponsors and other types of controlling shareholders and companies that do not have controlling shareholders based on our belief that short-term ownership--such as exists in private equity sponsor-owned companies--generally entails financial policies aimed at achieving rapid returns for shareholders typically through aggressive debt leverage.

167. Financial sponsors often dictate policies regarding risk-taking, financial management, and corporate governance for the companies that they control. There is a common pattern of these investors extracting cash in ways that increase the companies' financial risk by utilizing debt or debt like instruments. Accordingly, the financial risk profile we assign to companies that are controlled by financial sponsors ordinarily reflect our presumption of some deterioration in credit quality or steadily high leverage in the medium term.

168. We assess the influence of financial sponsor ownership as "FS-4", "FS-5", "FS-6", and "FS-6 (minus)" depending on how aggressive we assume the sponsor will be and assign a financial risk profile accordingly (see table 24).

169. Generally, financial sponsor-owned issuers will receive an assessment of "FS-6" or "FS-6 (minus)", leading to a financial risk profile assessment of '6', under the criteria. A "FS-6" assessment indicates that, in our opinion, forecasted credit ratios in the medium term are likely be to be consistent with a '6' financial risk profile, based on our assessment of the financial sponsor's financial policy and track record. A "FS-6 (minus)" will likely be applied to companies that we forecast to have near-term credit ratios consistent with a '6' financial risk profile, but we believe the financial sponsor to be very aggressive and that leverage could increase materially even further from our forecasted levels.

170. In a small minority of cases, a financial sponsor-owned entity could receive an assessment of "FS-5". This assessment will apply only when we project that the company's leverage will be consistent with a '5' (aggressive) financial risk profile (see tables 17, 18, and 19), we perceive that the risk of releveraging is low based on the company's financial policy and our view of the owner's financial risk appetite, and liquidity is at least adequate.

171. In even rarer cases, we could assess the financial policy of a financial sponsor-owned entity as "FS-4". This assessment will apply only when all of the following conditions are met: other shareholders own a material (generally, at least 20%) stake, we expect the sponsor to relinquish control over the intermediate term, we project that leverage is currently consistent with a '4' (significant) financial risk profile (see tables 17, 18, and 19), the company has said it will maintain leverage at or below this level, and liquidity is at least adequate.

Table 24

Financial Risk Profile Implications For Sponsor-Owned Issuers

Assessment	What it Means	Guidance
FS-4	Financial risk profile set at '4'	Issuer must meet all of the following conditions: • Other shareholders must own a material (no less than 20%) stake; • We anticipate that the sponsor will relinquish control over the medium term; • For issuers subject to Table 17 (standard volatility), debt to EBITDA is less than 4x, and we estimate that it will remain less than 4x. For issuers that are subject to Table 18 (medial volatility), debt to EBITDA is below 4.5x and we forecast it to remain below that level. Or for issuers subject to Table 19 (low volatility), debt to EBITDA is less than 5x and our estimation is it will remain below that level; • The company has indicated a financial policy stipulating a level of leverage consistent with a significant or better financial risk profile (that is, debt to EBITDA of less than 4x when applying standard volatility tables, 4.5x when applying medial volatility tables, or less than 5x when applying low volatility tables) and • We assess liquidity to be at least adequate, with adequate covenant headroom.
FS-5	Financial risk profile set at '5'	Issuer must meet all of the following conditions: • For issuers subject to the standard volatility table, debt to EBITDA is less than 5x, and we estimate that it will remain less than 5x. For issuers that are subject to the medial volatility table, debt to EBITDA is below 5.5x and we forecast it to remain below that level. Or for issuers subject to the low volatility table, debt to EBITDA is less than 6x and our estimation is it will remain below that level; • We believe the risk of releveraging beyond 5x (standard volatility issuer), 5.5x (medial volatility issuer), or 6x (low volatility issuer) is low; and • We assess liquidity to be at least adequate, with adequate covenant headroom.
FS-6	Financial risk profile set at '6'	Standard & Poor's debt to EBITDA is greater than 5x (when applying the standard volatility table), greater than 5.5x (when applying the medial volatility table), or greater than 6x (when applying the low volatility table). However, we believe leverage is unlikely to increase meaningfully beyond these levels.
FS-6 (minus)	Financial risk profile set at '6', and rating reduced by one notch (unless this results in a final rating below 'B-')	In determining the anchor rating the financial risk profile is a '6', but we believe the track record of the financial sponsor indicates that leverage could increase materially from already high levels.

3. Companies not controlled by a financial sponsor

172. For companies not controlled by a financial sponsor we evaluate management's financial discipline and financial policy framework to determine the influence on an entity's financial risk profile beyond what is implied by recent credit ratios and our cash flow and leverage forecasts. This influence can be positive, neutral, or negative.

173. We do not distinguish between management and a controlling shareholder that is not a financial sponsor when assessing these subfactors, as the controlling shareholder usually has the final say on financial policy.

a) Financial discipline

174. The financial discipline assessment is based on management's leverage tolerance and the likelihood of event risk. The criteria evaluate management's potential appetite to incur unforeseen, higher financial risk over a prolonged period and the associated impact on credit measures. We also assess management's capacity and commitment to rapidly decrease debt leverage to levels consistent with its credit ratio targets.

175. This assessment therefore seeks to determine whether unforeseen actions by management to increase, maintain, or reduce financial risk are likely to occur during the next two to three years, with either a negative or positive effect, or none at all, on our baseline forecasts for the period.

176. This assessment is based on the leverage tolerance of a company's management, as reflected in its plans or history of acquisitions, shareholder remuneration, and organic growth strategies (see Appendix E, paragraphs 258 to 263).

177. We assess financial discipline as positive, neutral, or negative, based on its potential impact on our forward-looking assessment of a firm's cash flow/leverage, as detailed in table 25. For example, a neutral assessment for leverage tolerance reflects our expectation that management's financial policy will unlikely lead to significant deviation from current and forecasted credit ratios. A negative assessment acknowledges a significant degree of event risk of increased leverage relative to our base-case forecast, resulting from the company's acquisition policy, its shareholder remuneration policy, or its organic growth strategy. A positive assessment indicates that the company is likely to take actions to reduce leverage, but we cannot confidently incorporate these actions into our baseline forward-looking assessment of cash flow/leverage.

178. A positive assessment indicates that management is committed and has the capacity to reduce debt leverage through the rapid implementation of credit enhancing measures, such as asset disposals, rights issues, or reductions in shareholder returns. In addition, management's track record over the past five years shows that it has taken actions to rapidly reduce unforeseen increases in debt leverage and that there have not been any prolonged periods when credit ratios were weaker than our expectations for the rating. Management, even if new, also has a track record of successful execution. Conversely, a negative assessment indicates management's financial policy allows for significant increase in leverage compared with both current levels and our forward-looking forecast under normal operating/financial conditions or does not have observable time limits or stated boundaries. Management has a track record of allowing for significant and prolonged peaks in leverage and there is no commitment or track record of management using mitigating measures to rapidly return to credit ratios consistent with our expectations.

179. As evidence of management's leverage tolerance, we evaluate its track record and plans regarding acquisitions, shareholder remuneration, and organic growth strategies (see Appendix E, paragraphs 258 to 263). Acquisitions could increase the risk that leverage will be higher than our base-case forecast if we view management's strategy as opportunistic or if its financial policy (if it exists) provides significant headroom for debt-financed acquisitions. Shareholder remuneration could also increase the risk of leverage being higher than our base-case forecast if management's shareholder reward policies are not particularly well defined or have no clear limits, management has a tolerance for shareholder returns exceeding operating cash flow, or has a track record of sustained cash returns despite weakening operating performance or credit ratios. Organic growth strategies can also result in leverage higher than our base-case forecast if these plans have no clear focus or investment philosophy, capital spending is fairly unpredictable,

or there is a track record of overspending or unexpected or rapid shifts in plans for new markets or products.

180. We also take into account management's track record and level of commitment to its stated financial policies, to the extent a company has a stated policy. Historical evidence and any deviations from stated policies are key elements in analyzing a company's leverage tolerance. Where material and unexpected deviation in leverage may occur (for example, on the back of operating weakness or acquisitions), we also assess management's plan to restore credit ratios to levels consistent with previous expectations through rapid and proactive non-organic measures. Management's track record to execute its deleveraging plan, its level of commitment, and the scope and timeframe of debt mitigating measures will be key differentiators in assessing a company's financial policy discipline.

Table 25

Assessing Financial Discipline

Descriptor	What it means	Guidance
Positive	Management is likely to take actions that result in leverage that is lower than our base-case forecast, but can't be confidently included in our base-case assumptions. Event risk is low.	Management is committed and has capacity to reduce debt leverage and increase financial headroom through the rapid implementation of credit enhancing measures, in line with its stated financial policy, if any. This relates primarily to management's careful and moderate policy with regard to acquisitions and shareholder remuneration as well as to its organic growth strategy. The assessments are supported by historical evidence over the past five years of not showing any prolonged weakening in the company's credit ratios, or relative to our base-case credit metrics' assumptions. Management, even if new, has a track record of successful execution.
Neutral	Leverage is not expected to deviate materially from our base-case forecast. Event risk is moderate.	Management's financial discipline with regard to acquisitions, shareholder remuneration, as well as its organic growth strategy does not result in significantly different leverage as defined in its stated financial policy framework.
Negative	Leverage could become materially higher than our base-case forecast. Event risk is high.	Management's financial policy framework does not explicitly rule out a significant increase in leverage compared to our base-case assumptions, possibly reflecting a greater event risk with regard to its M&A and shareholder remuneration policy as well as to its organic growth strategy. These points are supported by historical evidence over the past five years of allowing for significant and prolonged peaks in leverage, which remained unmitigated by credit supporting measures by management.

b) Financial policy framework

181. The company's financial policy framework assesses the comprehensiveness, transparency, and sustainability of the entity's financial policies (see Appendix E, paragraphs 264-268). This will help determine whether there is a satisfactory degree of visibility into the issuer's future financial risk profile. Companies that have developed and sustained a comprehensive set of financial policies are more likely to build long-term, sustainable credit quality than those that do not.

182. We will assess a company's financial policy framework as supportive or non-supportive based on evidence that supports the characteristics listed below. In order for an entity to receive a supportive assessment for financial policy framework, there must be sufficient evidence of management's financial policies to back that assessment.

183. A company assessed as supportive will generally exhibit the following characteristics:

- Management has a comprehensive set of financial policies covering key areas of financial risk, including debt leverage and liability management. Financial targets are well defined and quantifiable.
- Management's financial policies are clearly articulated in public forums (such as public listing disclosures and investor presentations) or are disclosed to a limited number of key stakeholders such as main creditors or to the credit rating agencies. The company's adherence to these policies is satisfactory.

- Management's articulated financial policies are considered achievable and sustainable. This assessment takes into consideration historical adherence to articulated policies, existing financial risk profile, capacity to sustain capital structure through nonorganic means, demands of key stakeholders, and the stability of financial policy parameters over time.

184. A company receives a non-supportive assessment if it does not meet all the conditions for a supportive assessment. We expect a non-supportive assessment to be uncommon.

I. Liquidity

185. Our assessment of liquidity focuses on monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis assesses the potential for a company to breach covenant tests related to declines in EBITDA, as well as its ability to absorb high-impact, low-probability events, the nature of the company's bank relationships, its standing in credit markets, and how prudent (or not) we believe its financial risk management to be (see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013).

J. Management And Governance

186. The analysis of management and governance addresses how management's strategic competence, organizational effectiveness, risk management, and governance practices shape the issuer's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. Stronger management of important strategic and financial risks may enhance creditworthiness (see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012).

K. Comparable Ratings Analysis

187. The comparable ratings analysis is our last step in determining a SACP on a company. This analysis can lead us to raise or lower our anchor, after adjusting for the modifiers, on a company by one notch based on our overall assessment of its credit characteristics for all subfactors considered in arriving at the SACP. This involves taking a holistic review of a company's stand-alone credit risk profile, in which we evaluate an issuer's credit characteristics in aggregate. A positive assessment leads to a one-notch upgrade, a negative assessment leads to a one-notch downgrade, and a neutral assessment indicates no change to the anchor.

188. The application of comparable ratings analysis reflects the need to "fine-tune" ratings outcomes, even after the use of each of the other modifiers. A positive or negative assessment is therefore likely to be common rather than exceptional.

189. We consider our assessments of each of the underlying subfactors to be points within a possible range. Consequently, each of these assessments that ultimately generate the SACP can be at the upper or lower end, or at the mid-point, of such a range:

- A company receives a positive assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be at the higher end of the range;
- A company receives a negative assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be at the lower end of the range;
- A company receives a neutral assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be in line with the middle of the range.

190. The most direct application of the comparable ratings analysis is in the following circumstances:

- Business risk assessment. If we expect a company to sustain a position at the higher or lower end of the ranges for the business risk category assessment, the company could receive a positive or negative assessment, respectively.
- Financial risk assessment and financial metrics. If a company's actual and forecasted metrics are just above (or just below) the financial risk profile range, as indicated in its cash flow/leverage assessment, we could assign a positive or negative assessment.

191. We also consider additional factors not already covered, or existing factors not fully captured, in arriving at the SACP. Such factors will generally reflect less frequently observed credit characteristics, may be unique, or may reflect unpredictability or uncertain risk attributes, both positive and negative.

192. Some examples that we typically expect could lead to a positive or negative assessment using comparable ratings analysis include:

- Short operating track record. For newly formed companies or companies that have experienced transformational events, such as a significant acquisition, a lack of an established track record of operating and financial performance could lead to a negative assessment until such a track record is established.
- Entities in transition. A company in the midst of changes that we anticipate will strengthen or weaken its creditworthiness and that are not already fully captured elsewhere in the criteria could receive a positive or negative assessment. Such a transition could occur following major divestitures or acquisitions, or during a significant overhaul of its strategy, business, or financial structure.
- Industry or macroeconomic trends. When industry or macroeconomic trends indicate a strengthening or weakening of the company's financial condition that is not already fully captured elsewhere in the criteria, the company could receive a positive or negative assessment, respectively.
- Unusual funding structures. A company with exceptional financial resources that the criteria do not capture in the traditional ratio or liquidity analysis, or in capital structure analysis, could receive a positive assessment.
- Contingent risk exposures. How well (or not) a company identifies, manages, and reserves for contingent risk exposures that can arise if guarantees are called, derivative contract break clauses are activated, or substantial lawsuits are lost could lead to a negative assessment.

SUPERSEDED CRITERIA FOR ISSUERS WITHIN THE SCOPE OF THESE CRITERIA

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- How Stock Prices Can Affect An Issuer's Credit Rating, Sept. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Credit FAQ: Knowing The Investors In A Company's Debt And Equity, April 4, 2006

RELATED CRITERIA

- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Criteria: Ratios And Adjustments, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
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- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
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- Principles Of Credit Ratings, published Feb. 16, 2011
- Stand-Alone Credit Profiles: One Component Of A Rating, Oct. 1, 2010
- Criteria Guidelines For Recovery Ratings On Global Industrial Issuers' Speculative-Grade Debt, Aug. 10, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

APPENDIXES

A. Country Risk

Table 26

Country And Regional Risk

Region
Western Europe
Southern Europe
Western + Southern Europe
East Europe
Central Europe
Eastern Europe and Central Asia
Middle East
Africa
North America
Central America
Latin America
The Caribbean
Asia-Pacific
Central Asia
East Asia
Australia NZ

Country	Region	GDP weighting (%)
South Africa	Africa	30.2
Egypt	Africa	28.0
Nigeria	Africa	23.5
Morocco	Africa	8.9

Table 26

Country And Regional Risk (cont.)		
Tunisia	Africa	5.4
Senegal	Africa	1.4
Mozambique	Africa	1.4
Zambia	Africa	1.2
Indonesia	Asia-Pacific	27.1
Taiwan	Asia-Pacific	20.1
Thailand	Asia-Pacific	14.4
Malaysia	Asia-Pacific	11.0
Philippines	Asia-Pacific	9.5
Vietnam	Asia-Pacific	7.1
Bangladesh	Asia-Pacific	6.8
Sri Lanka	Asia-Pacific	2.8
Laos	Asia-Pacific	0.4
Papua New Guinea	Asia-Pacific	0.4
Mongolia	Asia-Pacific	0.3
Australia	Australia NZ	88.2
New Zealand	Australia NZ	11.8
Guatemala	Central America	40.5
Costa Rica	Central America	30.2
Panama	Central America	29.3
India	Central Asia	86.5
Pakistan	Central Asia	9.3
Kazakhstan	Central Asia	4.2
Poland	Central Europe	46.3
Czech Republic	Central Europe	16.6
Hungary	Central Europe	11.3
Slovakia	Central Europe	7.7
Bulgaria	Central Europe	6.0
Croatia	Central Europe	4.6
Lithuania	Central Europe	3.8
Latvia	Central Europe	2.1
Estonia	Central Europe	1.6
China	East Asia	64.5
Japan	East Asia	23.6
Korea	East Asia	8.4
Hong Kong	East Asia	1.9
Singapore	East Asia	1.7
Greece	East Europe	77.5
Slovenia	East Europe	16.0
Cyprus	East Europe	6.5
Russia	Eastern Europe and Central Asia	80.4
Ukraine	Eastern Europe and Central Asia	10.8

Table 26

Country And Regional Risk (cont.)		
Belarus	Eastern Europe and Central Asia	4.8
Azerbaijan	Eastern Europe and Central Asia	3.2
Georgia	Eastern Europe and Central Asia	0.9
Brazil	Latin America	35.3
Mexico	Latin America	26.3
Argentina	Latin America	11.1
Colombia	Latin America	7.5
Venezuela	Latin America	6.0
Peru	Latin America	4.9
Chile	Latin America	4.8
Ecuador	Latin America	2.0
Uruguay	Latin America	0.8
El Salvador	Latin America	0.7
Paraguay	Latin America	0.6
Belize	Latin America	0.0
Turkey	Middle East	42.8
Saudi Arabia	Middle East	28.2
Israel	Middle East	9.4
Qatar	Middle East	7.2
Kuwait	Middle East	6.3
Oman	Middle East	3.4
Jordan	Middle East	1.5
Bahrain	Middle East	1.2
United States	North America	91.5
Canada	North America	8.5
Italy	Southern Europe	52.6
Spain	Southern Europe	40.4
Portugal	Southern Europe	7.0
Dominican Republic	The Caribbean	75.4
Jamaica	The Caribbean	19.2
Barbados	The Caribbean	5.4
Germany	Western Europe	28.7
United Kingdom	Western Europe	21.3
France	Western Europe	20.7
Netherlands	Western Europe	6.5
Belgium	Western Europe	3.9
Sweden	Western Europe	3.6
Switzerland	Western Europe	3.3
Austria	Western Europe	3.3
Norway	Western Europe	2.6
Denmark	Western Europe	1.9
Finland	Western Europe	1.8

Table 26

Country And Regional Risk (cont.)		
Ireland	Western Europe	1.8
Luxembourg	Western Europe	0.4
Iceland	Western Europe	0.1
Malta	Western Europe	0.1

B. Competitive Position

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles

Industry	Subsector	Competitive position group profile
Transportation cyclical	Airlines	Capital or asset focus
	Marine	Capital or asset focus
	Trucking	Capital or asset focus
Auto OEM	Automobile and truck manufacturers	Capital or asset focus
Metals and mining downstream	Aluminum	Commodity focus/cost driven
	Steel	Commodity focus/cost driven
Metals and mining upstream	Coal and consumable fuels	Commodity focus/cost driven
	Diversified metals and mining	Commodity focus/cost driven
	Gold	Commodity focus/cost driven
	Precious metals and minerals	Commodity focus/cost driven
Homebuilders and developers	Homebuilding	Capital or asset focus
Oil and gas refining and marketing	Oil and gas refining and marketing	Commodity focus/scale driven
Forest and paper products	Forest products	Commodity focus/cost driven
	Paper products	Commodity focus/cost driven
Building Materials	Construction materials	Capital or asset focus
Oil and gas integrated, exploration and production	Integrated oil and gas	Commodity focus/scale driven
	Oil and gas exploration and production	Commodity focus/scale driven
Agribusiness and commodity foods	Agricultural products	Commodity focus/scale driven
Real estate investment trusts (REITs)	Diversified REITs	Real-estate specific*
	Health care REITS	Real-estate specific*
	Industrial REITs	Real-estate specific*
	Office REITs	Real-estate specific*
	Residential REITs	Real-estate specific*
	Retail REITs	Real-estate specific*
	Specialized REITs	Not appplicable**
	Self-storage REITs	Real-estate specific*
	Net lease REITs	Real-estate specific*
	Real estate operating companies	Real-estate specific*
Leisure and sports	Casinos and gaming	Services and product focus
	Hotels, resorts, and cruise lines	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)

	Leisure facilities	Services and product focus
Commodity chemicals	Commodity chemicals	Commodity focus/cost driven
	Diversified chemicals	Commodity focus/cost driven
	Fertilizers and agricultural chemicals	Commodity focus/cost driven
Auto suppliers	Auto parts and equipment	Capital or asset focus
	Tires and rubber	Capital or asset focus
	Vehicle-related suppliers	Capital or asset focus
Aerospace and defense	Aerospace and defense	Services and product focus
Technology hardware and semiconductors	Communications equipment	Capital or asset focus
	Computer hardware	Capital or asset focus
	Computer storage and peripherals	Capital or asset focus
	Consumer electronics	Capital or asset focus
	Electronic equipment and instruments	Capital or asset focus
	Electronic components	Capital or asset focus
	Electronic manufacturing services	Capital or asset focus
	Technology distributors	Capital or asset focus
	Office electronics	Capital or asset focus
	Semiconductor equipment	Capital or asset focus
	Semiconductors	Capital or asset focus
Specialty Chemicals	Industrial gases	Capital or asset focus
	Specialty chemicals	Capital or asset focus
Capital Goods	Electrical components and equipment	Capital or asset focus
	Heavy equipment and machinery	Capital or asset focus
	Industrial componentry and consumables	Capital or asset focus
	Construction equipment rental	Capital or asset focus
	Industrial distributors	Services and product focus
Engineering and construction	Construction and engineering	Services and product focus
Railroads and package express	Railroads	Capital or asset focus
	Package express	Services and product focus
	Logistics	Services and product focus
Business and consumer services	Consumer services	Services and product focus
	Distributors	Services and product focus
	Facilities services	Services and product focus
	General support services	Services and product focus
	Professional services	Services and product focus
Midstream energy	Oil and gas storage and transportation	Commodity focus/scale driven
Technology software and services	Internet software and services	Services and product focus
	IT consulting and other services	Services and product focus
	Data processing and outsourced services	Services and product focus
	Application software	Services and product focus
	Systems software	Services and product focus
	Consumer software	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)		
Consumer durables	Home furnishings	Services and product focus
	Household appliances	Services and product focus
	Housewares and specialties	Services and product focus
	Leisure products	Services and product focus
	Photographic products	Services and product focus
	Small appliances	Services and product focus
Containers and packaging	Metal and glass containers	Capital or asset focus
	Paper packaging	Capital or asset focus
Media and entertainment	Ad agencies and marketing services companies	Services and product focus
	Ad-supported internet content platforms	Services and product focus
	Broadcast TV networks	Services and product focus
	Cable TV networks	Services and product focus
	Consumer and trade magazines	Services and product focus
	Data/professional publishing	Services and product focus
	Directories	Services and product focus
	E-Commerce (services)	Services and product focus
	Educational publishing	Services and product focus
	Film and TV programming production	Capital or asset focus
	Miscellaneous media and entertainment	Services and product focus
	Motion picture exhibitors	Services and product focus
	Music publishing	Services and product focus
	Music recording	Services and product focus
	Newspapers	Services and product focus
	Outdoor advertising	Services and product focus
	Printing	Commodity focus/scale driven
	Radio broadcasters	Services and product focus
	Trade shows	Services and product focus
	TV stations	Services and product focus
Oil and gas drilling, equipment and services	Onshore contract drilling	Commodity focus/scale driven
	Offshore contract drilling	Capital or Asset Focus
	Oil and gas equipment and services (oilfield services)	Commodity focus/scale driven
Retail and restaurants	Catalog retail	Services and product focus
	Internet retail	Services and product focus
	Department stores	Services and product focus
	General merchandise stores	Services and product focus
	Apparel retail	Services and product focus
	Computer and electronics retail	Services and product focus
	Home improvement retail	Services and product focus
	Specialty stores	Services and product focus
	Automotive retail	Services and product focus
	Home furnishing retail	Services and product focus

Table 27

List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)		
Health care services	Health care services	Commodity focus/scale driven
Transportation infrastructure	Airport services	National industries and utilities
	Highways	National industries and utilities
	Railtracks	National industries and utilities
	Marine ports and services	National industries and utilities
Environmental services	Environmental and facilities services	Services and product focus
Regulated utilities	Electric utilities	National industries and utilities
	Gas utilities	National industries and utilities
	Multi-utilities	National industries and utilities
	Water utilities	National industries and utilities
Unregulated power and gas	Independent power producers and energy traders	Capital or asset focus
	Merchant power	Capital or asset focus
Pharmaceuticals	Branded pharmaceuticals	Services and product focus
	Generic pharmaceuticals	Commodity focus/scale driven
Health care equipment	High-tech health care equipment	Product focus/scale driven
	Low-tech health care equipment	Commodity focus/scale driven
Branded nondurables	Brewers	Services and product focus
	Distillers and vintners	Services and product focus
	Soft drinks	Services and product focus
	Packaged foods and meats	Services and product focus
	Tobacco	Services and product focus
	Household products	Services and product focus
	Apparel, footwear, accessories, and luxury goods	Services and product focus
	Personal products	Services and product focus
Telecommunications and cable	Cable and satellite	Services and product focus
	Alternative carriers	Services and product focus
	Integrated telecommunication services	Services and product focus
	Wireless towers	Capital or asset focus
	Data center operators	Capital or asset focus
	Fiber-optic carriers	Capital or asset focus
	Wireless telecommunication services	Services and product focus

*See "Key Credit Factors For The Real Estate Industry," published Nov. 19, 2013. **For specialized REITs, there is no standard CPGP, as the CPGP will vary based on the underlying industry exposure (e.g. a forest and paper products REIT).

1. Analyzing subfactors for competitive advantage

193. Competitive advantage is the first component of our competitive position analysis. Companies that possess a sustainable competitive advantage are able to capitalize on key industry factors or mitigate associated risks more effectively. When a company operates in more than one business, we analyze each segment separately to form an overall view of its competitive advantage. In assessing competitive advantage, we evaluate the following subfactors:

- Strategy;
- Differentiation/uniqueness, product positioning/bundling;

- Brand reputation and marketing;
- Product/service quality;
- Barriers to entry, switching costs;
- Technological advantage and capabilities, technological displacement; and
- Asset profile.

a) Strategy

194. A company's business strategy will enhance or undermine its market entrenchment and business stability. Compelling business strategies can create a durable competitive advantage and thus a relatively stronger competitive position. We form an opinion as to the source and sustainability (if any) of the company's competitive advantage relative to its peers'. The company may have a differentiation advantage (i.e., brand, technology, regulatory) or a cost advantage (i.e., lower cost producer/servicer at the same quality level), or a combination.

195. Our assessment of a company's strategy is informed by a company's historical performance and how realistic we view its forward-looking business objectives to be. These may include targets for market shares, the percentage of revenues derived from new products, price versus the competition's, sales or profit growth, and required investment levels. We evaluate these objectives in the context of industry dynamics and the attractiveness of the markets in which the company participates.

b) Differentiation/uniqueness, product positioning/bundling

196. The attributes of product or service differentiation vary by sector, and may include product or services features, performance, durability, reliability, delivery, and comprehensiveness, among other measures. The intensity of competition may be lower where buyers perceive the product or service to be highly differentiated or to have few substitutes. Conversely, products and services that lack differentiation, or offer little value-added in the eyes of customers, are generally commodity-type products that primarily compete on price. Competition intensity will often be highest where limited or moderate investment (R&D, capital expenditures, or advertising) or low employee skill levels (for service businesses) are required to compete. Independent market surveys, media commentaries, market share trends, and evidence of leading or lagging when it comes to raising or lowering prices can indicate varying degrees of product differentiation.

197. Product positioning influences how companies are able to extend or protect market shares by offering popular products or services. A company's abilities to replace aging products with new ones, or to launch product extensions, are important elements of product positioning. In addition, the ability to sell multiple products or services to the same customer, known as bundling or cross-selling, (for instance, offering an aftermarket servicing contract together with the sale of a new appliance) can create a competitive advantage by increasing customers' switching costs and fostering loyalty.

c) Brand reputation and marketing

198. Brand equity measures the price premium a company receives based on its brand relative to the generic equivalent. High brand equity typically translates into customer loyalty, built partially via marketing campaigns. One measure of advertising effectiveness can be revenue growth compared with the increase in advertising expenses.

199. We also analyze re-investment and advertising strategies to anticipate potential strengthening or weakening of a

company's brand. A company's track record of boosting market share and delivering attractive margins could indicate its ability to build and maintain brand reputation.

d) Product/service level quality

200. The strength and consistency of a value proposition is an important factor contributing to a sustainable competitive advantage. Value proposition encompasses the key features of a product or a service that convince customers that their purchase has the right balance between price and quality. Customers generally perceive a product or a service to be good if their expectations are consistently met. Quality, both actual and perceived, can help a company attract and retain customers. Conversely, poor product and service quality may lead to product recalls, higher-than-normal product warnings, or service interruptions, which may reduce demand. Measures of customer satisfaction and retention, such as attrition rates and contract renewal rates, can help trace trends in product/service quality.

201. Maintaining the value proposition requires consistency and adaptability around product design, marketing, and quality-related operating controls. This is pertinent where product differentiation matters, as is the case in most noncommodity industries, and especially so where environmental or human health (concerns for the chemical, food, and pharmaceutical industries) adds a liability dimension to the quality and value proposition. Similarly, regulated utilities (which often do not set their own prices) typically focus on delivering uninterrupted service, often to meet the standards set by their regulator.

e) Barriers to entry, switching costs

202. Barriers to entry can reduce or eliminate the threat of new market entrants. Where they are effective, these barriers can lead to more predictable revenues and profits, by limiting pricing pressures and customer losses, lowering marketing costs, and improving operating efficiency. While barriers to entry may enable premium pricing, a dominant player may rationally choose pricing restraint to further discourage new entrants.

203. Barriers to entry can be one or more of: a natural or regulatory monopoly; supportive regulation; high transportation costs; an embedded customer base that would incur high switching costs; a proprietary product or service; capital or technological intensiveness.

204. A natural monopoly may result from unusually high requirements for capital and operating expenditures that make it uneconomic for a market to support more than a single, dominant provider. The ultimate barrier to entry is found among regulated utilities, which provide an essential service in their 'de juris' monopolies and receive a guaranteed rate of return on their investments. A supportive regulatory regime can include rules and regulations with high hurdles that discourage competitors, or mandate so many obligations for a new entrant as to make market entry financially unviable.

205. In certain industrial sectors, proprietary access to a limited supply of key raw materials or skilled labor, or zoning laws that effectively preclude a new entrant, can provide a strong barrier to entry. Factors such as relationships, long-term contracts or maintenance agreements, or exclusive distribution agreements can result in a high degree of customer stickiness. A proprietary product or service that's protected by a copyright or patent can pose a significant hurdle to new competitors.

f) Technological advantage and capabilities, technological displacement

206. A company may benefit from a proprietary technology that enables it to offer either a superior product or a commodity-type product at a materially lower cost. Proven research and development (R&D) capabilities can deliver a differentiated, superior product or service, as in the pharmaceutical or high tech sectors. However, optimal R&D strategies or the importance or effectiveness of patent protection differ by industry, stage of product development, and product lifecycle.

207. Technological displacement can be a threat in many industries; new technologies or extensions of current ones can effectively displace a significant portion of a company's products or services.

g) Asset profile

208. A company's asset profile is a reflection of its reinvestment, which creates tangible or intangible assets, or both. Companies in similar sectors and industries usually have similar reinvestment options and, thus, their asset profiles tend to be comparable. The reinvestment in "heavy" industries, such as oil and gas, metals and mining, and automotive, tends to produce more tangible assets, whereas the reinvestment in certain "light" industries, such as services, media and entertainment, and retail, tends to produce more intangible assets.

209. We evaluate how a company's asset profile supports or undermines its competitive advantage by reviewing its manufacturing or service creation capabilities and investment requirements, its distribution capabilities, and its track record and commitment to reinvesting in its asset base. This may include a review of the company's ability to attract and retain a talented workforce; its degree of vertical integration and how that may help or hinder its ability to secure supply sources, control the value-added part of its production chain, or adjust to technological developments; or its ability develop a broad and strong distribution network.

2. Analyzing subfactors for scale, scope, and diversity

210. In assessing the relative strength of this component, we evaluate four subfactors:

- Diversity of product or service range;
- Geographic diversity;
- Volumes, size of markets and revenues, and market shares; and
- Maturity of products or services.

211. In a given industry, entities with a broader mix of business activities are typically lower risk, and entities with a narrower mix are higher risk. High concentration of business volumes by product, customer, or geography, or a concentration in the production footprint or supplier base, can lead to less stable and predictable revenues and profits. Comparatively broader diversity helps a company withstand economic, competitive, or technological threats better than its peers.

212. There is no minimum size criterion, although size often provides a measure of diversification. Size and scope of operations is important relative to those of industry peers, though not in absolute terms. While relatively smaller companies can enjoy a high degree of diversification, they will likely be, almost by definition, more concentrated in terms of product, number of customers, or geography than their larger peers in the same industry.

213. Successful and continuing diversification supports a stronger competitive position. Conversely, poor diversification

weakens overall competitive position. For example, a company will weaken its overall business position if it enters new product lines and countries where it has limited expertise and lacks critical mass to be a real competitor to the incumbent market leaders. The weakness is greater when the new products or markets are riskier than the traditional core business.

214. Where applicable, we also include under scale, scope, and diversity an assessment of the potential benefits derived from unconsolidated (or partially consolidated) investments in strategic assets. The relative significance of such an investment and whether it is in an industry that exhibits high or, conversely, low correlation with the issuer's businesses would be considered in determining its potential benefits to scale, scope, and diversity. This excludes nonstrategic, financial investments, the analysis of which does not fall under the competitive position criteria but, instead, under the capital structure criteria.

a) Diversity of product or service range

215. The concentration of business volumes or revenues in a particular or comparatively small set of products or services can lead to less stable revenues and profits. Even if this concentration is in an attractive product or service, it may be a weakness. Likewise, the concentration of business volumes with a particular customer or a small group of customers, or the reliance on one or a few suppliers, can expose the company to a potentially greater risk of losing and having to replace related revenues and profits. On the other hand, successful diversification across products, customers, and/or suppliers can lead to more stable and predictable revenues and profits, which supports a stronger assessment of scale, scope, and diversity.

216. The relative contribution of different products or services to a company's revenues or profits helps us gauge its diversity. We also evaluate the correlation of demand between product or services lines. High correlation in demand between seemingly different product or service lines will accentuate volume declines during a weak part of the business cycle.

217. In most sectors, the share of revenue a company receives from its largest five to 10 customers or counterparties reveals how diversified its customer base is. However, other considerations such as the stability and credit quality of that customer base, and the company's ability to retain significant customers, can be mitigating or accentuating factors in our overall evaluation. Likewise, supplier dependency can often be measured based on a supplier's share of a company's operating or capital costs. However, other factors, such as the degree of interdependence between the company and its supplier(s), the substitutability of key supply sources, and the company's presumed ability to secure alternative supply without incurring substantial switching costs, are important considerations. Low switching costs (i.e. limited impact on input price, quality, or delivery times as a result of having to adapt to a new supply chain partner) can mitigate a high level of concentration.

b) Geographic diversity

218. We assess geographic diversity both from the standpoint of the breadth of the company's served or addressable markets, and from the standpoint of how geographically concentrated its facilities are.

219. The concentration of business volumes and revenues within a particular region can lead to greater exposure to economic factors affecting demand for a company's goods or services in that region. Even if the company's volumes and revenues are concentrated in an attractive region, it may still be vulnerable to a significant drop in demand for its

goods and services. Conversely, a company that serves multiple regions may benefit from different demand conditions in each, possibly resulting in greater revenue stability and more consistent profitability than a more focused peer's. That said, we consider geographic diversification in the context of the industry and the size of the local or regional economy. For instance, companies operating in local industries (such as food retailers) may benefit from a well-entrenched local position.

220. Generally, though, geographically concentrated production or service operations can expose a company to the risk of disruption, and damage revenues and profitability. Even when country risks don't appear significant, a company's vulnerability to exogenous factors (for example, natural disasters, labor or political unrest) increases with geographic concentration.

c) Volumes, size of markets and revenues, market share

221. Absolute sales or unit volumes and market share do not, by themselves, support a strong assessment of scale, scope, and diversity. Yet superior market share is a positive, since it may indicate a broad range of operations, products, or services.

222. We view volume stability (relative to peers') as a positive especially when: a company has demonstrated it during an economic downturn; if it has been achieved without relying on greater price concessions than competitors have made; and when it is likely to be sustained in the future. However, volume stability combined with shrinking market share could be evidence of a company's diminishing prospects for future profitability. We assess the predictability of business volumes and the likely degree of future volume stability by analyzing the company's performance relative to peers' on several industry factors: cyclicality; ability to adapt to technological and regulatory threats; the profile of the customer base (stickiness); and the potential life cycle of the company's products or services.

223. Depending on the industry sector, we measure a company's relative size and market share based on unit sales; the absolute amount of revenues; and the percentage of revenues captured from total industry revenues. We also adjust for industry and company specific qualitative considerations. For example, if an industry is particularly fragmented and has a number of similarly sized participants, none may have a particular advantage or disadvantage with respect to market share.

d) Maturity of products or services

224. The degree of maturity and the relative position on the lifecycle curve of the company's product or service portfolio affect the stability and sustainability of its revenues and margins. It is important to identify the stage of development of a company's products or services in order to measure the life cycle risks that may be associated with key products or services.

225. Mature products or services (e.g. consumer products or broadcast programming) are not necessarily a negative, in our view, if they still contribute reliable profits. If demand is declining for a company's product or service, we examine its track record on introducing new products with staying power. Similarly, a company's track record with product launches is particularly relevant.

3. Analyzing subfactors for operating efficiency

226. In assessing the relative strength of this component, we consider four subfactors:

- Cost structure,
- Manufacturing processes,
- Working capital management, and
- Technology.

227. To the extent a company has high operating efficiency, it should be able to generate better profit margins than peers that compete in the same markets, whatever the prevailing market conditions. The ability to minimize manufacturing and other operational costs and thus maximize margins and cash flow--for example, through manufacturing excellence, cost control, and diligent working capital management--will provide the funds for research and development, marketing, and customer service.

a) Cost structure

228. Companies that are well positioned from a cost standpoint will typically enjoy higher capacity utilization and be more profitable over the course of the business cycle. Cost structure and cost control are keys to generating strong profits and cash flow, particularly for companies that produce commodities, operate in mature industries, or face pricing pressures. It is important to consider whether a company or any of its competitors has a sustainable cost advantage, which can be based on access to cheaper energy, favorable manufacturing locations, or lower and more flexible labor costs, for example.

229. Where information is available, we examine a company's fixed versus variable cost mix as an indication of operating leverage, a measure of how revenue growth translates into growth in operating income. A company with significant operating leverage may witness dramatic declines in operating profit if unit volumes fall, as during cyclical downturns. Conversely, in an upturn, once revenues pass the breakeven point, a substantial percentage of incremental revenues typically becomes profit.

b) Manufacturing process

230. Capital intensity characterizes many heavy manufacturing sectors that require minimum volumes to produce acceptable profits, cash flow, and return on assets. We view capacity utilization through the business cycle (combined with the cost base) as a good indication of manufacturers' ability to maintain profits in varying economic scenarios. Our capacity utilization assessment is based on a company's production capacity across its manufacturing footprint. In addition, we consider the direction of a company's capacity utilization in light of our unit sales expectations, as opposed to analyzing it plant-by-plant.

231. Labor relations remain an important focus in our analysis of operating efficiency for manufacturers. Often, a company's labor cost structure is driven by its history of contractual negotiations and the countries in which it operates. We examine the rigidity or flexibility of a company's labor costs and the extent to which it relies on labor rather than automation. We analyze labor cost structure by assessing the extent of union representation, wage and benefit costs as a share of cost of goods sold (when available), and by assessing the balance of capital equipment vs. labor input in the manufacturing process. We also incorporate trends in a company's efforts to transfer labor costs from high-cost to low-cost regions.

c) Working capital management

232. Working capital management--of current or short-term assets and liabilities--is a key factor in our evaluation of operating efficiency. In general, companies with solid working capital management skills exhibit shorter cash conversion cycles (defined as days' investment in inventory and receivables less days' investment in accounts payable) than their lower-skilled peers. Short cash-conversion cycles could, for instance, demonstrate that a company has a stronger position in the supply chain (for example, requiring suppliers or dealers to hold more of its inventory). This allows a company to direct more capital than its peers can to other areas of investment.

d) Technology

233. Technology can play an important role in achieving superior operating efficiency through effective yield management (by improving input/output ratios), supply chain automation, and cost optimization.

234. Achieving high yield management is particularly important in industries with limited inventory and high fixed costs, such as transportation, lodging, media, and retail. The most efficient airlines can achieve higher revenue per available seat mile than their peers, while the most efficient lodging companies can achieve a higher revenue per available room than their peers. Both industries rely heavily on technology to effectively allocate inventory (seats and rooms) to maximize sales and profitability.

235. Effective supply chain automation systems enable companies to reduce investments in inventory and better forecast future orders based on current trends. By enabling electronic data interchange between supplier and retailer, such systems help speed orders and reorders for goods by quickly pinpointing which merchandise is selling well and needs restocking. They also identify slow moving inventory that needs to be marked down, making space available for fresh merchandise.

236. Effective use of technology can also help hold down costs by improving productivity via automation and workflow management. This can reduce selling, general, and administrative costs, which usually represent a substantial portion of expenditures for industries with high fixed costs, thus boosting earnings.

4. Industry-specific SER parameters

Table 28

SER Calibration By Industry Based On EBITDA

	--Volatility of profitability assessment*--					
	1	2	3	4	5	6
Transportation cyclical	=<10%	>10%-14%	>14%-22%	>22%-33%	>33%-76%	>76%
Auto OEM	=<25%	>25%-33%	>33%-35%	>35%-40%	>40%-46%	>46%
Metals and mining downstream	=<16%	>16%-31%	>31%-42%	>42%-53%	>53%-82%	>82%
Metals and mining upstream	=<16%	>16%-23%	>23%-28%	>28%-34%	>34%-59%	>59%
Homebuilders and developers	=<19%	>19%-33%	>33%-46%	>46%-65%	>65%-95%	>95%
Oil and gas refining and marketing	=<14%	>14%-21%	>21%-35%	>35%-46%	>46%-82%	>82%
Forest and paper products	=<9%	>9%-18%	>18%-26%	>26%-51%	>51%-114%	>114%
Building materials	=<9%	>9%-16%	>16%-19%	>19%-24%	>24%-33%	>33%
Oil and gas integrated, exploration and production	=<12%	>12%-19%	>19%-22%	>22%-28%	>28%-38%	>38%
Agribusiness and commodity foods	=<12%	>12%-19%	>19%-25%	>25%-39%	>39%-57%	>57%

Table 28

SER Calibration By Industry Based On EBITDA (cont.)						
Real estate investment trusts (REITs)	=<5%	>5%-9%	>9%-13%	>13%-20%	>20%-32%	>32%
Leisure and sports	=<5%	>5%-9%	>9%-12%	>12%-16%	>16%-24%	>24%
Commodity chemicals	=<14%	>14%-19%	>19%-28%	>28%-37%	>37%-51%	>51%
Auto suppliers	=<15%	>15%-20%	>20%-26%	>26%-32%	>32%-45%	>45%
Aerospace and defense	=<6%	>6%-9%	>9%-15%	>15%-24%	>24%-41%	>41%
Technology hardware and semiconductors	=<11%	>11%-15%	>15%-22%	>22%-31%	>31%-58%	>58%
Specialty chemicals	=<5%	>5%-10%	>10%-14%	>14%-23%	>23%-36%	>36%
Capital goods	=<12%	>12%-16%	>16%-21%	>21%-30%	>30%-45%	>45%
Engineering and construction	=<9%	>9%-14%	>14%-20%	>20%-28%	>28%-39%	>39%
Railroads and package express	=<5%	>5%-8%	>8%-10%	>10%-13%	>13%-22%	>22%
Business and consumer services	=<4%	>4%-8%	>8%-11%	>11%-16%	>16%-30%	>30%
Midstream energy	=<5%	>5%-9%	>9%-11%	>11%-15%	>15%-31%	>31%
Technology software and services	=<4%	>4%-9%	>9%-14%	>14%-19%	>19%-33%	>33%
Consumer durables	=<7%	>7%-10%	>10%-13%	>13%-19%	>19%-35%	>35%
Containers and packaging	=<5%	>5%-7%	>7%-12%	>12%-18%	>18%-26%	>26%
Media and entertainment	=<6%	>6%-10%	>10%-14%	>14%-20%	>20%-29%	>29%
Oil and gas drilling, equipment and services	=<16%	>16%-22%	>22%-28%	>28%-44%	>44%-62%	>62%
Retail and restaurants	=<4%	>4%-8%	>8%-11%	>11%-16%	>16%-26%	>26%
Health care services	=<4%	>4%-5%	>5%-9%	>9%-12%	>12%-19%	>19%
Transportation infrastructure	=<2%	>2%-4%	>4%-7%	>7%-12%	>12%-19%	>19%
Environmental services	=<5%	>5%-9%	>9%-13%	>13%-22%	>22%-29%	>29%
Regulated utilities	=<4%	>4%-7%	>7%-9%	>9%-14%	>14%-26%	>26%
Unregulated power and gas	=<7%	>7%-16%	>16%-20%	>20%-29%	>29%-47%	>47%
Pharmaceuticals	=<5%	>5%-8%	>8%-11%	>11%-17%	>17%-32%	>32%
Health care equipment	=<3%	>3%-5%	>5%-6%	>6%-10%	>10%-25%	>25%
Branded nondurables	=<4%	>4%-7%	>7%-10%	>10%-15%	>15%-43%	>43%
Telecommunications and cable	=<3%	>3%-6%	>6%-9%	>9%-13%	>13%-23%	>23%
Overall	=<5%	>5%-9%	>9%-15%	>15%-23%	>23%-43%	>43%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

Table 29

SER Calibration By Industry Based On EBITDA Margin						
	--Volatility of profitability assessment*--					
	1	**2**	**3**	**4**	**5**	**6**
Transportation cyclical	=<4%	>4%-8%	>8%-16%	>16%-28%	>28%-69%	>69%
Auto OEM	=<15%	>15%-19%	>19%-29%	>29%-31%	>31%-45%	>45%
Metals and mining downstream	=<10%	>10%-18%	>18%-26%	>26%-36%	>36%-56%	>56%
Metals and mining upstream	=<8%	>8%-10%	>10%-14%	>14%-19%	>19%-31%	>31%
Homebuilders and developers	=<10%	>10%-18%	>18%-30%	>30%-56%	>56%-114%	>114%
Oil and gas refining and marketing	=<12%	>12%-22%	>22%-28%	>28%-42%	>42%-71%	>71%
Forest and paper products	=<8%	>8%-13%	>13%-21%	>21%-41%	>41%-117%	>117%
Building materials	=<4%	>4%-8%	>8%-13%	>13%-18%	>18%-23%	>23%

Table 29

SER Calibration By Industry Based On EBITDA Margin (cont.)						
Oil and gas integrated, exploration and production	=<4%	>4%-6%	>6%-8%	>8%-13%	>13%-22%	>22%
Agribusiness and commodity foods	=<9%	>9%-14%	>14%-18%	>18%-27%	>27%-100%	>100%
Real estate investment trusts (REITs)	=<2%	>2%-5%	>5%-8%	>8%-13%	>13%-34%	>34%
Leisure and sports	=<3%	>3%-5%	>5%-6%	>6%-9%	>9%-18%	>18%
Commodity chemicals	=<9%	>9%-14%	>14%-18%	>18%-25%	>25%-37%	>37%
Auto suppliers	=<9%	>9%-13%	>13%-18%	>18%-23%	>23%-40%	>40%
Aerospace and defense	=<3%	>3%-6%	>6%-7%	>7%-12%	>12%-24%	>24%
Technology hardware and semiconductors	=<7%	>7%-10%	>10%-15%	>15%-21%	>21%-62%	>62%
Specialty chemicals	=<3%	>3%-6%	>6%-10%	>10%-19%	>19%-28%	>28%
Capital goods	=<6%	>6%-9%	>9%-13%	>13%-20%	>20%-33%	>33%
Engineering and construction	=<6%	>6%-8%	>8%-12%	>12%-17%	>17%-26%	>26%
Railroads and package express	=<2%	>2%-6%	>6%-8%	>8%-10%	>10%-17%	>17%
Business and consumer services	=<3%	>3%-5%	>5%-7%	>7%-12%	>12%-22%	>22%
Midstream energy	=<3%	>3%-6%	>6%-9%	>9%-14%	>14%-28%	>28%
Technology software and services	=<3%	>3%-6%	>6%-10%	>10%-15%	>15%-30%	>30%
Consumer durables	=<4%	>4%-8%	>8%-11%	>11%-15%	>15%-26%	>26%
Containers and packaging	=<5%	>5%-7%	>7%-9%	>9%-15%	>15%-22%	>22%
Media and entertainment	=<4%	>4%-6%	>6%-9%	>9%-14%	>14%-24%	>24%
Oil and gas drilling, equipment and services	=<6%	>6%-12%	>12%-16%	>16%-22%	>22%-32%	>32%
Retail and restaurants	=<3%	>3%-5%	>5%-7%	>7%-12%	>12%-21%	>21%
Health care services	=<3%	>3%-5%	>5%-6%	>6%-8%	>8%-15%	>15%
Transportation infrastructure	=<1%	>1%-3%	>3%-5%	>5%-7%	>7%-15%	>15%
Environmental services	=<3%	>3%-4%	>4%-6%	>6%-10%	>10%-24%	>24%
Regulated utilities	=<4%	>4%-7%	>7%-9%	>9%-14%	>14%-24%	>24%
Unregulated power and gas	=<6%	>6%-10%	>10%-15%	>15%-23%	>23%-41%	>41%
Pharmaceuticals	=<4%	>4%-5%	>5%-7%	>7%-10%	>10%-21%	>21%
Health care equipment	=<2%	>2%-4%	>4%-5%	>5%-10%	>10%-16%	>16%
Branded nondurables	=<3%	>3%-6%	>6%-9%	>9%-13%	>13%-28%	>28%
Telecommunications and cable	=<2%	>2%-4%	>4%-5%	>5%-7%	>7%-13%	>13%
Overall	=<3%	>3%-6%	>6%-10%	>10%-16%	>16%-32%	>32%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

Table 30

SER Calibration By Industry Based On Return On Capital						
	--Volatility of profitability assessment*--					
	1	2	3	4	5	6
Transportation cyclical	=<14%	>14%-28%	>28%-39%	>39%-53%	>53%-156%	>156%
Auto OEM	=<42%	>42%-64%	>64%-74%	>74%-86%	>86%-180%	>180%
Metals and mining downstream	=<25%	>25%-32%	>32%-43%	>43%-53%	>53%-92%	>92%
Metals and mining upstream	=<22%	>22%-30%	>30%-38%	>38%-45%	>45%-93%	>93%
Homebuilders and developers	=<12%	>12%-31%	>31%-50%	>50%-70%	>70%-88%	>88%

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Table 30

SER Calibration By Industry Based On Return On Capital (cont.)						
Oil and gas refining and marketing	=<14%	>14%-30%	>30%-48%	>48%-67%	>67%-136%	>136%
Forest and paper products	=<10%	>10%-22%	>22%-40%	>40%-89%	>89%-304%	>304%
Building materials	=<13%	>13%-20%	>20%-26%	>26%-36%	>36%-62%	>62%
Oil and gas integrated, exploration and production	=<16%	>16%-22%	>22%-31%	>31%-43%	>43%-89%	>89%
Agribusiness and commodity foods	=<12%	>12%-15%	>15%-29%	>29%-55%	>55%-111%	>111%
Real estate investment trusts (REITs)	=<8%	>8%-14%	>14%-20%	>20%-26%	>26%-116%	>116%
Leisure and sports	=<11%	>11%-17%	>17%-26%	>26%-34%	>34%-64%	>64%
Commodity chemicals	=<19%	>19%-28%	>28%-41%	>41%-50%	>50%-73%	>73%
Auto suppliers	=<20%	>20%-39%	>39%-50%	>50%-67%	>67%-111%	>111%
Aerospace and defense	=<7%	>7%-13%	>13%-19%	>19%-27%	>27%-61%	>61%
Technology hardware and semiconductors	=<8%	>8%-21%	>21%-34%	>34%-49%	>49%-113%	>113%
Specialty chemicals	=<5%	>5%-18%	>18%-28%	>28%-43%	>43%-64%	>64%
Capital goods	=<15%	>15%-24%	>24%-31%	>31%-45%	>45%-121%	>121%
Engineering and construction	=<12%	>12%-21%	>21%-23%	>23%-33%	>33%-54%	>54%
Railroads and package express	=<3%	>3%-11%	>11%-17%	>17%-20%	>20%-27%	>27%
Business and consumer services	=<9%	>9%-17%	>17%-23%	>23%-40%	>40%-87%	>87%
Midstream energy	=<5%	>5%-11%	>11%-17%	>17%-22%	>22%-34%	>34%
Technology software and services	=<8%	>8%-21%	>21%-35%	>35%-65%	>65%-105%	>105%
Consumer durables	=<8%	>8%-13%	>13%-20%	>20%-35%	>35%-60%	>60%
Containers and packaging	=<6%	>6%-14%	>14%-23%	>23%-35%	>35%-52%	>52%
Media and entertainment	=<9%	>9%-17%	>17%-26%	>26%-40%	>40%-86%	>86%
Oil and gas drilling, equipment and services	=<25%	>25%-33%	>33%-45%	>45%-65%	>65%-90%	>90%
Retail and restaurants	=<6%	>6%-14%	>14%-18%	>18%-26%	>26%-69%	>69%
Health care services	=<6%	>6%-10%	>10%-15%	>15%-25%	>25%-44%	>44%
Transportation infrastructure	=<5%	>5%-9%	>9%-12%	>12%-16%	>16%-27%	>27%
Environmental Services	=<7%	>7%-12%	>12%-24%	>24%-35%	>35%-72%	>72%
Regulated utilities	=<6%	>6%-9%	>9%-13%	>13%-20%	>20%-36%	>36%
Unregulated power and gas	=<14%	>14%-19%	>19%-29%	>29%-55%	>55%-117%	>117%
Pharmaceuticals	=<6%	>6%-8%	>8%-15%	>15%-20%	>20%-33%	>33%
Health care equipment	=<4%	>4%-8%	>8%-19%	>19%-31%	>31%-81%	>81%
Branded nondurables	=<6%	>6%-10%	>10%-17%	>17%-29%	>29%-63%	>63%
Telecommunications and cable	=<7%	>7%-13%	>13%-19%	>19%-26%	>26%-60%	>60%
Overall	=<7%	>7%-15%	>15%-23%	>23%-38%	>38%-81%	>81%

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

C. Cash Flow/Leverage Analysis

1. The merits and drawbacks of each cash flow measure

a) EBITDA

237. EBITDA is a widely used, and therefore a highly comparable, indicator of cash flow, although it has significant limitations. Because EBITDA derives from the income statement entries, it can be distorted by the same accounting issues that limit the use of earnings as a basis of cash flow. In addition, interest can be a substantial cash outflow for speculative-grade companies and therefore EBITDA can materially overstate cash flow in some cases. Nevertheless, it serves as a useful and common starting point for cash flow analysis and is useful in ranking the financial strength of different companies.

b) Funds from operations (FFO)

238. FFO is a hybrid cash flow measure that estimates a company's inherent ability to generate recurring cash flow from its operations independent of working capital fluctuations. FFO estimates the cash flow available to the company before working capital, capital spending, and discretionary items such as dividends, acquisitions, etc.

239. Because cash flow from operations tends to be more volatile than FFO, FFO is often used to smooth period-over-period variation in working capital. We consider it a better proxy of recurring cash flow generation because management can more easily manipulate working capital depending on its liquidity or accounting needs. However, we do not generally rely on FFO as a guiding cash flow measure in situations where assessing working capital changes is important to judge a company's cash flow generating ability and general creditworthiness. For example, for working-capital-intensive industries such as retailing, operating cash flow may be a better indicator than FFO of the firm's actual cash generation.

240. FFO is a good measure of cash flow for well-established companies whose long-term viability is relatively certain (i.e., for highly rated companies). For such companies, there can be greater analytical reliance on FFO and its relation to the total debt burden. FFO remains very helpful in the relative ranking of companies. In addition, more established, healthier companies usually have a wider array of financing possibilities to cover potential short-term liquidity needs and to refinance upcoming maturities. For marginal credit situations, the focus shifts more to free operating cash flow--after deducting the various fixed uses such as working capital investment and capital expenditures--as this measure is more directly related to current debt service capability.

c) Cash flow from operations (CFO)

241. The measurement and analysis of CFO forms an important part of our ratings assessment, in particular for companies that operate in working-capital-intensive industries or industries in which working capital flows can be volatile. CFO is distinct from FFO as it is a pure measure of cash flow calculated after accounting for the impact on earnings of changes in operating assets and liabilities. CFO is cash flow that is available to finance items such as capital expenditures, repay borrowing, and pay for dividends and share buybacks.

242. In many industries, companies shift their focus to cash flow generation in a downturn. As a result, even though they typically generate less cash from ordinary business activities because of low capacity utilization and relatively low fixed-cost absorption, they may generate cash by reducing inventories and receivables. Therefore, although FFO is likely to be lower in a downturn, the impact on CFO may not be as great. In times of strong growth the opposite will be true, and consistently lower CFO compared to FFO without a corresponding increase in revenue and profitability can indicate an untenable situation.

243. Working capital is a key element of a company's cash flow generation. While there tends to be a need to build up working capital and therefore to consume cash in a growth or expansion phase, changes in working capital can also act as a buffer in case of a downturn. Many companies will sell off inventories and invest a lower amount in raw materials because of weaker business activities, both of which reduce the amount of capital and cash that is tied up in working capital. Therefore, working capital fluctuations can occur both in periods of revenue growth and contraction and analyzing a company's near-term working capital needs is crucial for estimating future cash flow developments.

244. Often, businesses that are capital intensive are not working-capital-intensive: most of the capital commitment is upfront in equipment and machinery, while asset-light businesses may have to invest proportionally more in inventories and receivables. That also affects margins, because capital-intensive businesses tend to have proportionally lower operating expenses (and therefore higher EBITDA margins), while working-capital-intensive businesses usually report lower EBITDA margins. The resulting cash flow volatility can be significant: because all investment is made upfront in a capital-intensive business, there is usually more room to absorb subsequent EBITDA volatility because margins are higher. For example, a capital-intensive company may remain reasonably profitable even if its EBITDA margin declines from 30% to 20%. By contrast, a working-capital-intensive business with a lower EBITDA margin (due to higher operating expenses) of 8% can post a negative EBITDA margin if EBITDA volatility is large.

d) Free operating cash flow (FOCF)

245. By deducting capital expenditures from CFO, we arrive at FOCF, which can be used as a proxy for a company's cash generated from core operations. We may exclude discretionary capital expenditures for capacity growth from the FOCF calculation, but in practice it is often difficult to discriminate between spending for expansion and replacement. And, while companies have some flexibility to manage their capital budgets to weather down cycles, such flexibility is generally temporary and unsustainable in light of intrinsic requirements of the business. For example, companies can be compelled to increase their investment programs because of strong demand growth or technological changes. Regulated entities (for example, telecommunications companies) might also face significant investment requirements related to their concession contracts (the understanding between a company and the host government that specifies the rules under which the company can operate locally).

246. Positive FOCF is a sign of strength and helpful in distinguishing between two companies with the same FFO. In addition, FOCF is helpful in differentiating between the cash flows generated by more and less capital-intensive companies and industries.

247. In highly capital-intensive industries (where maintenance capital expenditure requirements tend to be high) or in other situations in which companies have little flexibility to postpone capital expenditures, measures such as FFO to debt and debt to EBITDA may provide less valuable insight into relative creditworthiness because they fail to capture potentially meaningful capital expenditures. In such cases, a ratio such as FOCF to debt provides greater analytical insight.

248. A company serving a low-growth or declining market may exhibit relatively strong FOCF because of diminishing fixed and working capital needs. Growth companies, in contrast, exhibit thin or even negative FOCF because of the investment needed to support growth. For the low-growth company, credit analysis weighs the positive, strong current cash flow against the danger that this high level of cash flow might not be sustainable. For the high-growth company,

the opposite is true: weighing the negatives of a current cash deficit against prospects of enhanced cash flow once current investments begin yielding cash benefits. In the latter case, if we view the growth investment as temporary and not likely to lead to increased leverage over the long-term, we'll place greater analytical importance on FFO to debt rather than on FOCF to debt. In any event, we also consider the impact of a company's growth environment in our business risk analysis, specifically in a company's industry risk analysis (see section B).

e) Discretionary cash flow (DCF)

249. For corporate issuers primarily rated in the investment-grade universe, DCF to debt can be an important barometer of future cash flow adequacy as it more fully reflects a company's financial policy, including decisions regarding dividend payouts. In addition, share buybacks and potential M&A, both of which can represent very significant uses of cash, are important components in cash flow analysis.

250. The level of dividends depends on a company's financial strategy. Companies with aggressive dividend payout targets might be reluctant to reduce dividends even under some liquidity pressure. In addition, investment-grade companies are less likely to reduce dividend payments following some reversals--although dividends ultimately are discretionary. DCF is the truest reflection of excess cash flow, but it is also the most affected by management decisions and, therefore, does not necessarily reflect the potential cash flow available.

D. Diversification/Portfolio Effect

1. Academic research

251. Academic research recently concluded that, during the global financial crisis of 2007-2009, conglomerates had the advantage over single sector-focused firms because they had better access to the credit markets as a result of their debt co-insurance and used the internal capital markets more efficiently (i.e., their core businesses had stronger cash flows). Debt co-insurance is the view that the joining-together of two or more firms whose earnings streams are less-than-perfectly correlated reduces the risk of default of the merged firms (i.e., the co-insurance effect) and thereby increases the "debt capacity" or "borrowing ability" of the combined enterprise. These financing alternatives became more valuable during the crisis. (Source: "Does Diversification Create Value In The Presence Of External Financing Constraints? Evidence From The 2007-2009 Financial Crisis," Venkat Kuppuswamy and Belen Villalonga, Harvard Business School, Aug. 19, 2011.)

252. In addition, fully diversified, focused companies saw more narrow credit default swap spreads from 2004-2010 vs. less diversified firms. This highlighted that lenders were differentiating for risk and providing these companies with easier and cheaper access to capital. (Source: "The Power of Diversified Companies During Crises," The Boston Consulting Group and Leipzig Graduate School of Management, January 2012.)

253. Many rated conglomerates are either country- or region-specific; only a small percentage are truly global. The difference is important when assessing the country and macroeconomic risk factors. Historical measures for each region, based on volatility and correlation, reflect regional trends that are likely to change over time.

E. Financial Policy

1. Controlling shareholders

254. Controlling shareholder(s)--if they exist--exert significant influence over a company's financial risk profile, given their ability to use their direct or indirect control of the company's financial policies for their own benefit. Although the criteria do not associate the presence of controlling shareholder(s) to any predefined negative or positive impact, we assess the potential medium- to long-term implications for a company's credit standing of these strategies. Long-term ownership--such as exists in many family-run businesses--is often accompanied by financial discipline and reluctance to incur aggressive leverage. Conversely, short-term ownership--such as exists in private equity sponsor-owned companies--generally entails financial policies aimed at achieving rapid returns for shareholders typically through aggressive debt leverage.

255. The criteria define controlling shareholder(s) as:

- A private shareholder (an individual or a family) with majority ownership or control of the board of directors;
- A group of shareholders holding joint control over the company's board of directors through a shareholder agreement. The shareholder agreement may be comprehensive in scope or limited only to certain financial aspects; and
- A private equity firm or a group of private equity firms holding at least 40% in a company or with majority control of its board of directors.

256. A company is not considered to have a controlling shareholder if it is publicly listed with more than 50% of voting interest listed or when there is no evidence of a particular shareholder or group of shareholders exerting 'de facto' control over a company.

257. Companies that have as their controlling shareholder governments or government-related entities, infrastructure and asset-management funds, and diversified holding companies and conglomerates are assessed in separate criteria.

2. Financial discipline

a) Leverage influence from acquisitions

258. Companies may employ more or less acquisitive growth strategies based on industry dynamics, regulatory changes, market opportunities, and other factors. We consider management teams with disciplined, transparent acquisition strategies that are consistent with their financial policy framework as providing a high degree of visibility into the projected evolution of cash flow and credit measures. Our assessment takes into account management's track record in terms of acquisition strategy and the related impact on the company's financial risk profile. Historical evidence of limited management tolerance for significant debt-funded acquisitions provides meaningful support for the view that projected credit ratios would not significantly weaken as a result of the company's acquisition policy. Conversely, management teams that pursue opportunistic acquisition strategies, without well-defined parameters, increase the risks that the company's financial risk profile may deteriorate well beyond our forecasts.

259. Acquisition funding policies and management's track record in this respect also provide meaningful insight in terms of credit ratio stability. In the criteria, we take into account management's willingness and capacity to mobilize all funding resources to restore credit quality, such as issuing equity or disposing of assets, to mitigate the impact of sizable

acquisitions on credit ratios. The financial policy framework and related historical evidence are key considerations in our assessment.

b) Leverage influence from shareholder remuneration policies

260. A company's approach to rewarding shareholders demonstrates how it balances the interests of its various stakeholders over time. Companies that are consistent and transparent in their shareholder remuneration policies, and exhibit a willingness to adjust shareholder returns to mitigate adverse operating conditions, provide greater support to their long-term credit quality than other companies. Conversely, companies that prioritize cash returns to shareholders in periods of deteriorating economic, operating, or share price performance can significantly undermine long-term credit quality and exacerbate the credit impact of adverse business conditions. In assessing a company's shareholder remuneration policies, the criteria focus on the predictability of shareholder remuneration plans, including how a company builds shareholder expectations, its track record in executing shareholder return policies over time, and how shareholder returns compare with industry peers'.

261. Shareholder remuneration policies that lack transparency or deviate meaningfully from those of industry peers introduce a higher degree of event risk and volatility and will be assessed as less predictable under the criteria. Dividend and capital return policies that function primarily as a means to distribute surplus capital to shareholders based on transparent and stable payout ratios--after satisfying all capital requirements and leverage objectives of the company, and that support stable to improving leverage ratios--are considered the most supportive of long term credit quality.

c) Leverage influence from plans regarding investment decisions or organic growth strategies

262. The process by which a company identifies, funds, and executes organic growth, such as expansion into new products and/or new markets, can have a significant impact on its long-term credit quality. Companies that have a disciplined, coherent, and manageable organic growth strategy, and have a track record of successful execution are better positioned to continue to attract third-party capital and maintain long-term credit quality. By contrast, companies that allocate significant amounts of capital to numerous, unrelated, large and/or complex projects and often incur material overspending against the original budget can significantly increase their credit risk.

263. The criteria assess whether management's organic growth strategies are transparent, comprehensive, and measurable. We seek to evaluate the company's mid- to long-term growth objectives--including strategic rationales and associated execution risks--as well as the criteria it uses to allocate capital. Effective capital allocation is likely to include guidelines for capital deployment, including minimum return hurdles, competitor activity analysis, and demand forecasting. The company's track record will provide key data for this assessment, including how well it executes large and/or complex projects against initial budgets, cost overruns, and timelines.

3. Financial policy framework

a) Comprehensiveness of financial policy framework

264. Financial policies that are clearly defined, unambiguous, and provide a tight framework around management behavior are the most reliable in determining an issuer's future financial risk profile. We assess as consistent with a supportive assessment, policies that are clear, measurable, and well understood by all key stakeholders. Accordingly, the financial policy framework must include well-defined parameters regarding how the issuer will manage its cash flow protection

strategies and debt leverage profile. This includes at least one key or a combination of financial ratio constraints (such as maximum debt to EBITDA threshold) and the latter must be relevant with respect to the issuer's industry and/or capital structure characteristics.

265. By contrast, the absence of established financial policies, policies that are vague or not quantifiable, or historical evidence of significant and unexpected variation in management's long-term financial targets could contribute to an overall assessment of a non-supportive financial policy.

b) Transparency of financial policies

266. We assess as supportive financial policy objectives that are transparent and well understood by all key stakeholders and we view them as likely to influence an issuer's financial risk profile over time. Alternatively, financial policies, if they exist, that are not communicated to key stakeholders and/or where there is limited historical evidence to support the company's commitment to these policies, are non-supportive, in our view. We consider the variety of ways in which a company communicates its financial policy objectives, including public disclosures, investor presentation materials, and public commentary.

267. In some cases, however, a company may articulate its financial policy objectives to a limited number of key stakeholders, such as its main creditors or to credit rating agencies. In these situations, a company may still receive a supportive classification if we assess that there is a sufficient track record (more than three years) to demonstrate a commitment to its financial policy objectives.

c) Achievability and sustainability of financial policies

268. To assess the achievability and sustainability of a company's financial policies, we consider a variety of factors, including the entity's current and historical financial risk profile; the demands of its key stakeholders (including dividend and capital return expectations of equity holders); and the stability of the company's financial policies that we have observed over time. If there is evidence that the company is willing to alter its financial policy framework because of adverse business conditions or growth opportunities (including M&A), this could support an overall assessment of non-supportive.

4. Financial policy adjustments--examples

269. Example 1: A moderately leveraged company has just been sold to a new financial sponsor. The financial sponsor has not leveraged the company yet and there is no stated financial policy at the outset. We expect debt leverage to increase upon refinancing, but we are not able to factor it precisely in our forecasts yet.
Likely outcome: FS-6 financial policy assessment, implying that we expect the new owner to implement an aggressive financial policy in the absence of any other evidence.

270. Example 2: A company has two owners—a family owns 75%, a strategic owner holds the remaining 25%. Although the company has provided Standard & Poor's with some guidance on long-term financial objectives, the overall financial policy framework is not sufficiently structured nor disclosed to a sufficient number of stakeholders to qualify for a supportive assessment. Recent history, however, does not provide any evidence of unexpected, aggressive financial transactions and we believe event risk is moderate.
Likely outcome: Neutral financial policy impact, including an assessment of neutral for financial discipline. Although the company's financial framework does not support long-term visibility, historical evidence and stability of management suggest that event risk is not significant. The unsupportive financial framework assessment, however,

prevents the company from qualifying for an overall positive financial policy assessment, should the conditions for positive financial discipline be met.

271. Example 3: A company (not owned by financial sponsors) has stated leverage targets equivalent to a significant financial risk profile assessment. The company continues to make debt-financed acquisitions yet remains within its leverage targets, albeit at the weaker end of these. Our forecasts are essentially built on expectations that excess cash flow will be fully used to fund M&A or, possibly pay share repurchases, but that management will overall remain within its leverage targets.
Likely outcome: Neutral financial policy impact. Although management is fairly aggressive, the company consistently stays within its financial policy targets. We think our forecasts provide a realistic view of the evolution of the company's credit metrics over the next two years. No event risk adjustment is needed.

272. Example 4: A company (not owned by a financial sponsor) has just made a sizable acquisition (consistent with its long-term business strategy) that has brought its credit ratios out of line. Management expressed its commitment to rapidly improve credit ratios back to its long-term ratio targets--representing an acceptable range for the SACP--through asset disposals or a rights issue. We see their disposal plan (or rights issue) as realistic but precise value and timing are uncertain. At the same time, management has a supportive financial policy framework, a positive track record of five years, and assets are viewed as fairly easily tradable.
Likely outcome: Positive financial policy impact. Although forecast credit ratios will remain temporarily depressed, as we cannot fully factor in asset disposals (or rights issue) due to uncertainty on timing/value, or without leaking confidential information, the company's credit risk should benefit from management's positive track record and a satisfactory financial policy framework. The anchor will be better by one notch if management and governance is at least satisfactory and liquidity is at least adequate.

273. Example 5: A company (not owned by a financial sponsor) has very solid financial ratios, providing it with meaningful flexibility for M&A when compared with management's long-term stated financial policy. Also, its stock price performance is somewhat below that of its closest industry peers. Although we have no recent evidence of any aggressive financial policy steps, we fundamentally believe that, over the long-term term, the company will end up using its financial flexibility for the right M&A opportunity, or alternatively return cash to shareholders.
Likely outcome: Negative financial policy impact. Long-term event risk derived from M&A cannot be built into forecasts nor shareholder returns (share buybacks or one-off dividends) be built into forecasts to attempt aligning projected ratios with stated long-term financial policy levels. This is because our forecasts are based on realistic and reasonably predictable assumptions for the medium term. The anchor will be adjusted down, by one notch or more, because of the negative financial policy assessment.

F. Corporate Criteria Glossary

Anchor: The combination of an issuer's business risk profile assessment and its financial risk profile assessment determine the anchor. Additional rating factors can then modify the anchor to determine the final rating or SACP.

Asset profile: A descriptive way to look at the types and quality of assets that comprise a company (examples can include tangible versus intangible assets, those assets that require large and continuing maintenance, upkeep, or reinvestment, etc.).

Business risk profile: This measure comprises the risk and return potential for a company in the market in which it participates, the country risks within those markets, the competitive climate, and the competitive advantages and disadvantages the company has. The criteria combine the assessments for Corporate Industry and Country Risk Assessment (CICRA), and competitive position to determine a company's business risk profile assessment.

Capital-intensive company: A company exhibiting large ongoing capital spending to sales, or a large amount of depreciation to sales. Examples of capital-intensive sectors include oil production and refining, telecommunications, and transportation sectors such as railways and airlines.

Cash available for debt repayment: Forecast cash available for debt repayment is defined as the net change in cash for the period before debt borrowings and debt repayments. This includes forecast discretionary cash flow adjusted for our expectations of: share buybacks, net of any share issuance, and M&A. Discretionary cash flow is defined as cash flow from operating activities less capital expenditures and total dividends.

Competitive position: Our assessment of a company's: 1) competitive advantage; 2) operating efficiency; 3) scale, scope, and diversity; and 4) profitability.

- Competitive advantage--The strategic positioning and attractiveness to customers of the company's products or services, and the fragility or sustainability of its business model.
- Operating efficiency--The quality and flexibility of the company's asset base and its cost management and structure.
- Scale, scope, and diversity--The concentration or diversification of business activities.
- Profitability--Our assessment of both the company's level of profitability and volatility of profitability.

Competitive Position Group Profile (CPGP): Used to determine the weights to be assigned to the four components of competitive position. While industries are assigned to one of the six profiles, individual companies and industry subsectors can be classified into another CPGP because of unique characteristics. Similarly, national industry risk factors can affect the weighing. The six CPGPs are:

- Services and product focus,
- Product focus/scale driven,
- Capital or asset focus,
- Commodity focus/cost driven,
- Commodity focus/scale driven, and
- National industry and utilities.

Conglomerate: Companies that have at least three distinct business segments, each contributing between 10%-50% of EBITDA or FOCF. Such companies may benefit from the diversification/portfolio effect.

Controlling shareholders: Equity owners who are able to affect decisions of varying effect on operations, leverage, and shareholder reward without necessarily being a majority of shareholders.

Corporate Industry and Country Risk Assessment (CICRA): The result of the combination of an issuer's country risk assessment and industry risk assessment.

Debt co-insurance: The view that the joining-together of two or more firms whose earnings streams are less-than-perfectly correlated reduces the risk of default of the merged firms (i.e., the co-insurance effect) and thereby increases the "debt capacity" or "borrowing ability" of the combined enterprise. These financing alternatives became more valuable during the global financial crisis of 2007-2009.

Financial headroom: Measure of deviation tolerated in financial metrics without moving outside or above a pre-designated band or limit typically found in loan covenants (as in a debt to EBITDA multiple that places a constraint on leverage). Significant headroom would allow for larger deviations.

Financial risk profile: The outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to its financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.

Financial sponsor: An entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short to intermediate time frame. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.

Profitability ratio: Commonly measured using return on capital and EBITDA margins but can be measured using sector-specific ratios. Generally calculated based on a five-year average, consisting of two years of historical data, and our projections for the current year and the next two financial years.

Shareholder remuneration policies: Management's stated shareholder reward plans (such as a buyback or dividend amount, or targeted payout ratios).

Stand-alone credit profile (SACP): Standard & Poor's opinion of an issue's or issuer's creditworthiness, in the absence of extraordinary intervention or support from its parent, affiliate, or related government or from a third-party entity such as an insurer.

Transfer and convertibility assessment: Standard & Poor's view of the likelihood of a sovereign restricting nonsovereign access to foreign exchange needed to satisfy the nonsovereign's debt service obligations.

Unconsolidated equity affiliates: Companies in which an issuer has an investment, but which are not consolidated in an issuer's financial statements. Therefore, the earnings and cash flows of the investees are not included in our primary metrics unless dividends are received from the investees.

Upstream/midstream/downstream: Referring to exploration and production, transport and storage, and refining and distributing, respectively, of natural resources and commodities (such as metals, oil, gas, etc.).

Volatility of profitability/SER: We base the volatility of profitability on the standard error of the regression (SER) for a company's historical EBITDA. The SER is a statistical measure that is an estimate of the deviation around a 'best fit' trend line. We combine it with the profitability ratio to determine the final profitability assessment. We only calculate

SER when companies have at least seven years of historical annual data, to ensure that the results are meaningful.

Working-capital-intensive companies: Generally a company with large levels of working capital in relation to its sales in order to meet seasonal swings in working capital. Examples of working-capital-intensive sectors include retail, auto manufacturing, and capital goods.

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.

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Criteria | Corporates | Utilities:

Key Credit Factors For The Regulated Utilities Industry

November 19, 2013

*(**Editor's Note:** On July 22, 2020, we republished this criteria article to make nonmaterial changes. See the "Revisions And Updates" section for details.)*

This article presents S&P Global Ratings' methodology and assumptions for Regulated Utilities. This article relates to "Corporate Methodology" and "Principles Of Credit Ratings."

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SCOPE OF THE CRITERIA

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").

SUMMARY OF THE CRITERIA

This article presents S&P Global Ratings 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, specifically, the conditions to apply low, medial, and standard volatility tables. The section on liquidity for regulated utilities partially amends existing criteria. All

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other sections of the corporate criteria apply to the analysis of regulated utilities.

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METHODOLOGY

Part I--Business Risk Analysis

Industry risk

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.

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

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.

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

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

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

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

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

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

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

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

Regulatory independence and insulation:

- Market framework and energy policies that support long-term financial stability 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

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.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)

Qualifier	What it means	Guidance
	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.
		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.

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.

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

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.

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.

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.

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.

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.

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

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.

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.

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.

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.

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.

42. 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.

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.

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.

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

Level of profitability

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).

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.

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.

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

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.

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

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 unique to this sector are discussed below.

Accounting characteristics

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.
- 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.
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions.

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.

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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").

84. This paragraph has been deleted.

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.

REVISIONS AND UPDATES

This article was originally published on Nov. 19, 2013. These criteria became effective on Nov. 19, 2013.

Changes introduced after original publication:

- Following our periodic review completed on June 17, 2016, we updated the contact information and criteria references and deleted paragraphs 2, 5, and 6, which were related to the initial publication of our criteria and no longer relevant.

- Following our periodic review completed on June 6, 2017, we updated the contact information and criteria references and clarified paragraphs 4 and 84.
- Following our periodic review completed on June 5, 2018, we updated the contact information and criteria references and renamed the "Revision History" section to "Revisions And Updates."
- On April 1, 2019, we republished this criteria article to make nonmaterial changes. We deleted paragraphs 57-74 because they were superseded by "Corporate Methodology: Ratios And Adjustments," published April 1, 2019 (Ratios and Adjustments). The sector-specific accounting and analytical adjustments previously included in those paragraphs are now included in the Guidance supporting the Ratios and Adjustments criteria. We also updated the contacts list.
- On July 25, 2019, we republished this criteria article to make nonmaterial changes. We updated the contact information and updated several references to other criteria articles throughout the body of this article by removing the dates of publication. These dates are provided in the "Related Criteria" section.
- On Dec. 4, 2019, we republished this criteria article to make nonmaterial changes. We deleted paragraph 84 because it was superseded by "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers" (liquidity criteria), published Dec. 16, 2014. The sector-specific liquidity adjustments previously included in that paragraph are now included in the guidance supporting the liquidity criteria. We also updated criteria references.
- On July 22, 2020, we republished this criteria article to make nonmaterial changes to update criteria references.

RELATED PUBLICATIONS

Superseded Criteria

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

Related Criteria

- Group Rating Methodology, July 1, 2019
- Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Methodology: Jurisdiction Ranking Assessments, Jan. 21, 2016
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, 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
- Securitizing Stranded Costs, Jan. 18, 2001

Related Guidance

- Guidance: Liquidity Descriptors For Global Corporate Issuers, Dec. 4, 2019
- Guidance: Group Rating Methodology, July 1, 2019
- Guidance: Corporate Methodology: Ratios And Adjustments, April 1, 2019

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.

Case No. 2020-00349 and 2020-00350
Exhibit DKA-6
Comparative Cost of Debt

Utilty Cost of Debt Comparison
12 Months Ending June 30, 2020

Rank	Company	Per Public Data
1.	Duke Energy Ohio	3.550%
2.	Public Service Electric and Gas Company	3.707%
3.	AEP Texas	3.715%
4.	Indiana Michigan Power Company	3.790%
5.	PECO Energy Company	3.884%
6.	Union Electric Company	3.926%
7.	NiSource	3.934%
8.	Duke Energy Indiana Inc.	3.974%
9.	Kentucky Power Company	4.001%
10.	**KU***	**4.027%**
11.	Dayton Power and Light	4.055%
12.	**LG&E***	**4.064%**
13.	Commonwealth Edison	4.082%
14.	DTE Electric Company	4.083%
15.	Ameren Illinois Company	4.203%
16.	PPL Electric Utilities	4.281%
17.	DTE Gas Company	4.440%
18.	Appalachian Power Company	4.602%
19.	Pennsylvania Electric Company	4.614%
20.	Metropolitan Edison Company	4.766%
21.	Ohio Power Company	4.994%
22.	Jersey Central Power & Light Co.	5.196%
23.	Ohio Edison Company	7.092%
24.	Toledo Edison Company	8.162%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE YEAR SURCREDIT	**)**	**CASE NO. 2020-00349**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE YEAR SURCREDIT	**)**	**CASE NO. 2020-00350**

TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

on behalf of

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA

TABLE OF CONTENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Adrien M. McKenzie, and my business address is 3907 Red River, Austin, Texas 78751.

Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am President of Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic, and policy consulting to business and government.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A3. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit No. 1.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. The purpose of my testimony is to present to the Kentucky Public Service Commission ("KPSC") my independent assessment of the fair rate of return on equity ("ROE") that Louisville Gas and Electric Company ("LGE") and Kentucky Utilities Company ("KU") should be authorized to earn on their investment in providing electric and gas utility service.[1] In addition, I also examined the reasonableness of the Companies' capital structure, considering both the specific risks faced by LGE/KU, as well as other industry guidelines.

Q5. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A5. To prepare my testimony, I referenced information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the

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[1] I refer to LGE and KU collectively as "LGE/KU" or "the Companies."

organization, finances, and operations of LGE and KU from my participation in prior proceedings before the KPSC, the Virginia State Corporation Commission ("VSCC"), and the Federal Energy Regulatory Commission ("FERC"). In connection with this filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to LGE/KU. I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for the Companies, and they form the basis of my analyses and conclusions.

Q6. HOW IS YOUR TESTIMONY ORGANIZED?

A6. After first summarizing my conclusions and recommendations, I briefly review the operations and finances of LGE and KU. I then examine current conditions in the capital markets and their implications in evaluating a fair ROE for the Companies. With this as a background, I conduct well-accepted quantitative analyses to estimate the current cost of equity for a reference group of comparable-risk utilities. These included the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical form of Capital Asset Pricing Model ("ECAPM"), an equity risk premium approach based on allowed ROEs, and reference to expected earned rates of return for utilities, which are all methods that are commonly relied on in regulatory proceedings. In addition, I discuss the proper use of data from Regulatory Research Associates ("RRA") in reviewing recommendations concerning the required ROE and explain why the development and consideration of substantial record evidence is necessary to meet the regulatory principles set forth by the U.S. Supreme Court in the *Bluefield*[2] and *Hope*[3] cases.

Based on the cost of equity estimates indicated by my analyses, I evaluate a fair ROE for LGE/KU, taking into account the specific risks for their jurisdictional utility operations in Kentucky and the Companies' requirements for financial strength, which are properly considered in setting a fair ROE. Further, I corroborate my utility quantitative analyses by applying the DCF model to a group of low risk non-utility firms.

II. RETURN ON EQUITY FOR LGE/KU

Q7. WHAT IS THE PURPOSE OF THIS SECTION?

A7. This section presents my conclusions regarding the fair ROE applicable to LGE/KU's electric and gas utility operations. This section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Importance of Financial Strength

Q8. WHAT IS THE ROLE OF THE ROE IN SETTING A UTILITY'S RATES?

A8. The ROE is the cost of attracting and retaining common equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a fair and reasonable ROE is integral in meeting sound regulatory economics and the standards set forth by the

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[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[3] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

U.S. Supreme Court in the *Bluefield* and *Hope* cases. A utility's allowed ROE should be sufficient to: 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but they can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

While the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates, these and subsequent cases enshrined the importance of an end result that meets the opportunity cost standard of finance. Under this doctrine, the required return is established by investors in the capital markets based on expected returns available from comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (*e.g.,* DCF and CAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of capital market data in order to evaluate an ROE that will produce a balanced and fair end result for investors and customers.

Q9. THROUGHOUT YOUR TESTIMONY YOU REFER REPEATEDLY TO THE CONCEPTS OF "FINANCIAL STRENGTH," "FINANCIAL INTEGRITY," AND "FINANCIAL FLEXIBILITY." WOULD YOU BRIEFLY DESCRIBE WHAT YOU MEAN BY THESE TERMS?

A9. These terms are generally synonymous and refer to the utility's ability to attract and retain the capital that is necessary to provide service at reasonable cost, consistent with the Supreme Court standards. LGE/KU's plans call for a continuation of capital investments in generation, transmission and distribution systems and technology to preserve and enhance service reliability for their customers. The Companies must generate adequate cash flow from operations to fund these requirements and for repayment of maturing debt, together with access to capital from external sources under reasonable terms, on a sustainable basis.

Rating agencies and potential debt investors tend to place significant emphasis on maintaining strong financial metrics and credit ratings that support access to debt capital markets under reasonable terms. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors. Investors understand the important role that a supportive regulatory environment plays in establishing a sound financial profile that will permit the utility access to debt and equity capital markets on reasonable terms in both favorable financial markets and during times of potential disruption and crisis.

Q10. WHAT PART DOES REGULATION PLAY IN ENSURING THAT LGE/KU HAVE ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A SUSTAINABLE BASIS?

A10. Regulatory signals are a major driver of investors' risk assessment for utilities. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. As Moody's Investors Service ("Moody's") noted, "the regulatory environment is the most important driver of our outlook because it sets the pace for cost recovery."[4] Similarly, S&P Global Ratings ("S&P") observed that, "Regulatory advantage is the most heavily weighted

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[4] Moody's Investors Service, "Regulation Will Keep Cash Flow Stable As Major Tax Break Ends," *Industry Outlook* (Feb. 19, 2014).

factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[5]

The Value Line Investment Survey ("Value Line") summarized these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[6]

Furthermore, the ROE set by the KPSC impacts investor confidence in not only the jurisdictional utility, but also in the ultimate parent company that is the entity that actually issues common stock.

Q11. DO CUSTOMERS BENEFIT BY ENHANCING THE COMPANIES' FINANCIAL FLEXIBILITY?

A11. Yes. Providing an ROE that is sufficient to maintain LGE/KU's ability to attract capital under reasonable terms, even in times of financial and market stress, is not only consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Customers enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure safe and reliable service.

B. Recommended ROE

Q12. WHAT IS YOUR RECOMMENDATION AS TO A FAIR RATE OF RETURN ON EQUITY FOR LGE/KU?

A12. I recommend an ROE of 10.0% for LGE/KU's utility operations. The bases for my conclusion are summarized below:

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[5] S&P Global Ratings, *Assessing U.S. Investors-Owned Utility Regulatory Environments*, RatingsExpress (Aug. 10, 2016).

[6] Value Line Investment Survey, *Water Utility Industry* (January 13, 2017) at p. 1780.

- In order to reflect the risks and prospects associated with LGE/KU's jurisdictional utility operations, my analyses focused on a proxy group of nineteen other utilities with both electric and gas operations ("Utility Group").
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM, ECAPM, and risk premium methods to estimate a fair ROE for LGE/KU, as well as referencing the expected earnings approach.
- As summarized on Exhibit No. 2, considering the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I conclude that the cost of equity for the proxy group of utilities is in the 9.3% to 10.5% range.
- Adding a flotation cost adjustment of 10 basis points to this bare bones cost of equity range results in an ROE range for the proxy group of 9.4% to 10.6%.
- An ROE of 10.0% is equal to the midpoint of the proxy group range with the flotation cost adjustment.
- Considering capital market expectations and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, an ROE of 10.0% is fair for LGE/KU.

Q13. WHAT ELSE SHOULD BE CONSIDERED IN WEIGHING YOUR QUANTITATIVE RESULTS?

A13. No single methodology used to estimate the cost of equity is inherently superior, and the results of alternative quantitative approaches should serve as an integral part of the decision-making underlying the determination of a just and reasonable ROE. For example, the Federal Energy Regulatory Commission ("FERC") noted that dislocations in the economy and capital markets can undermine the reliability of quantitative methodologies used to estimate the cost of equity, concluding that "any DCF analysis may be affected by potentially unrepresentative financial inputs to the

DCF formula, including those produced by historically anomalous capital market conditions."[7]

In this light, it is important to consider alternatives to the DCF model. As shown in Exhibit No. 2, alternative risk premium models (i.e., the CAPM, ECAPM, and utility risk premium approaches) produce ROE estimates that generally exceed the DCF results. My expected earnings approach corroborated these outcomes.

Q14. IN RECENT ORDERS IN LGE/KU'S ENVIRONMENTAL SURCHARGE CASES, THE KPSC CONCLUDED THAT THE PREVIOUSLY APPROVED ROE OF 9.725% WAS AN "UNNECESSARILY HIGH RATE."[8] WHAT WAS BASIS FOR THIS CONCLUSION?

A14. The KPSC cited "material changes in the economy, including but not limited to lowered interest rates, changes in the Federal Reserve policies, and additional changes in the economy."[9] The orders in these proceedings suggested that trends in economic data "indicates a massive reduction in capital costs."[10] Additionally, the KPSC determined that information in the environmental surcharge proceedings suggested that the ROE was "directionally lower," and cited my testimony submitted on behalf of Kentucky Power Company ("KPCo") in Case No. 2020-0174 as support for this conclusion.[11]

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[7] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, at P 41 (2014).
[8] *Electronic Application of Kentucky Utilities Company for Approval of Its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060, Order at 18 (Sep. 29, 2020); *Electronic Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and a Revised Environmental Surcharge*, Case No. 2020-00061, Order at 18 (Sep. 29, 2020).
[9] *Id.*
[10] *Id.* at 21.
[11] *Id.* at 19, 21.

Q15. DOES YOUR EVIDENCE IN THIS CASE SUPPORT A REDUCTION TO LGE/KU'S PREVIOUSLY APPROVED ROE?

A15. No. As I indicate above, the results of quantitative approaches applied using current data warrant an increase, not a decrease, to the Companies' ROE. As my evidence explains, the threat posed by the COVID-19 pandemic has led to a reevaluation of risks and required returns, including for utility common stocks. As my testimony demonstrates:

- The turmoil in financial markets has resulted in a fundamental shift in investors' risk perceptions, which has increased the cost of common equity capital.
- The dramatic increase in market volatility that has accompanied the COVID-19 pandemic is indicative of significantly higher investment risks.
- Rising beta values support the view that the forward-looking risks of electric utility stocks have increased, which implies a higher ROE.
- Because of the "flight to quality," bond yields have fallen sharply while the required returns for common stocks have moved higher to compensate for increased perceptions of risk. As a result, trends in Treasury bond yields do not provide a relevant benchmark in evaluating a fair ROE for LGE/KU in the current capital market climate.
- In contrast to equity markets, unprecedented Federal Reserve monetary policies—which include the purchase of utility bonds in the secondary market—have placed artificial downward pressure on interest rates.

Q16. DOES YOUR TESTIMONY IN CASE NO. 2020-00174 ON BEHALF OF KPCO SUPPORT A REDUCTION IN LGE/KU'S ROE?

A16. No. My direct testimony in Case No. 2020-00174 supported a recommended ROE of 10.3%,[12] and I indicated that the results of the quantitative analyses underlying this conclusion did not fully reflect the economic and financial market implications of the COVID-19 pandemic. My subsequent rebuttal testimony in that proceeding, which was filed with the KPSC on November 9, 2020, continued to support the reasonableness of a 10.3% ROE for KPCo based on the results of updated analyses.[13] Nothing in my submissions in Case No. 2020-0174 contradicts my evidence in this case supporting a 10.0% ROE for LGE/KU.

Q17. DO THE DCF RESULTS FOR YOUR SELECT GROUP OF NON-UTILITY FIRMS SUPPORT THE REASONABLENESS OF A 10.0% ROE FOR LGE/KU?

A17. Yes. Average DCF estimates for a low-risk group of firms in the competitive sector of the economy range from 9.6% to 10.3% and averaged 9.9% before consideration of flotation costs. While I did not base my recommendation on these results, they confirm that a 10.0% ROE falls in a reasonable range to maintain LGE/KU's financial integrity, provide a return commensurate with investments of comparable risk, and support the Companies' ability to attract capital.

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[12] *Electronic Application of Kentucky Power Company for (1) a General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief*, Case No. 2020-00174, Direct Testimony of Adrien M. McKenzie at 4 (Ky. P.S.C. June 29, 2020).

[13] Case No. 2020-00174, Rebuttal Testimony of Adrien M. McKenzie (Ky. P.S.C. Nov. 9, 2020).

Q18. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANIES' CAPITAL STRUCTURE?

A18. As explained more fully later in my testimony, I concluded that a common equity ratio of approximately 53% represents a reasonable basis from which to calculate an overall rate of return for LGE and KU. This conclusion was based on the following findings:

- LGE/KU's common equity ratio is well within the range of capitalizations maintained by the firms in the proxy group of utilities and is consistent with the capitalization maintained by other electric utility operating companies based on data at year-end 2019 and near-term expectations;
- The requested capitalization reflects the need to support the credit standing and financial flexibility of LGE/KU as the Companies seek to fund system investments and meet the requirements of customers; and
- Ongoing economic and capital market uncertainties also influence the appropriate capital structure for LGE/KU, and the Companies must maintain adequate equity to preserve the flexibility necessary to maintain continuous access to capital even during times of unfavorable market conditions.

III. FUNDAMENTAL ANALYSES

Q19. WHAT IS THE PURPOSE OF THIS SECTION?

A19. My objective is to evaluate and opine as to a just and reasonable ROE for LGE/KU. Much of my work is predicated on a comparison of LGE/KU within the utility industry as a whole, and more specifically to a proxy group of publicly traded utilities. As a foundation for my opinions and subsequent quantitative analyses, this section briefly reviews the operations and finances of LGE and KU. In addition, I explain the basis for my proxy group used to estimate the cost of equity and examine alternative objective indicators of investment risk applicable to these firms. I also evaluate the investment risks of LGE/KU against those of my reference group, as well as examining specific conditions impacting todays' capital markets. An understanding of the fundamental factors driving the risks and prospects of utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Louisville Gas and Electric Company and Kentucky Utilities Company

Q20. BRIEFLY DESCRIBE LGE AND KU.

A20. Along with LGE, KU is a wholly owned subsidiary of LG&E and KU Energy LLC ("LKE"), which in turn is a wholly owned subsidiary of PPL Corporation ("PPL"). KU is principally engaged in providing regulated electric utility service. In addition to serving approximately 530,000 retail customers in central, southeastern, and western Kentucky, KU also serves approximately 28,000 customers in southwestern Virginia. LGE is principally engaged in providing regulated electric and gas utility service in Louisville and adjacent areas. LGE serves approximately 418,000 electric customers and provides natural gas utility service to approximately 329,000 customers.

Although KU and LGE are separate operating subsidiaries, they are operated as a single, fully integrated system. The Companies' utility facilities include combined ownership or interests in approximately 7,561 megawatts ("MW") of generating capacity. Coal-fired generating stations account for approximately 62% of LGE/KU's combined generating capacity and produced approximately 79% of the electricity generated by the Companies in 2019. The electric transmission and distribution systems of KU and LGE include approximately 20,700 and 7,200 miles of lines, respectively. In addition, LGE's natural gas utility system includes more than 4,300 miles of distribution mains and nearly 400 miles of transmission pipelines, along with five underground natural gas storage fields with a current working natural gas capacity of approximately 15 Bcf. As of December 31, 2019, LGE and KU had total assets of $7.1 and $8.8 billion, respectively, with annual revenues totaling approximately $1.5 and $1.7 billion.

LGE/KU's retail electric operations are subject to the jurisdiction of the KPSC, with FERC regulating the Companies' interstate transmission and wholesale operations. In addition, KU is subject to regulation by the VSCC.

Q21. HOW ARE FLUCTUATIONS IN THE COMPANIES' OPERATING EXPENSES CAUSED BY VARYING ENERGY MARKET CONDITIONS ACCOMMODATED IN THEIR RATES?

A21. LGE/KU's retail electric rates in Kentucky contain a fuel adjustment clause ("FAC"), whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. The KPSC also requires that electric utilities, including LGE/KU, file documents relating to fuel procurement and the purchase of power and energy from other utilities.

With respect to LGE's gas utility operations, the gas supply clause ("GSC") adjusts natural gas rates on a periodic basis for the difference between the actual gas costs and those collected from customers, subject to review by the KPSC. The GSC provides for quarterly rate adjustments to reflect the expected cost of natural gas supply in that quarter. In addition, the GSC contains a mechanism whereby any over- or under-recoveries of natural gas supply cost from prior quarters are to be refunded to or recovered from customers through the adjustment factor determined for subsequent quarters.

Q22. WHERE DO LGE/KU OBTAIN THE CAPITAL USED TO FINANCE INVESTMENT IN UTILITY PLANT?

A22. As wholly owned subsidiaries, the Companies' common equity capital is provided through LKE. Ultimately, LKE obtains investor-supplied common equity capital solely from PPL, whose common stock is publicly traded on the New York Stock Exchange. In addition to capital supplied by PPL, LGE and KU also issue first mortgage bonds and tax-exempt debt securities in their own name.

Q23. DO THE COMPANIES ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?

A23. Yes. The Companies will require additional investment to provide for necessary maintenance and replacements of their utility infrastructure, as well as to fund investment in new facilities, with capital expenditures for 2020 to 2024 expected to total $1.9 billion and $2.3 billion for LGE and KU, respectively.[14] Moody's informed investors that LGE and KU are "in the midst of a large capital investment plan," and that total capital expenditures represent about 39% and 34% of their respective net book value of property, plant, and equipment.[15] S&P labels the Companies' financial risk as "significant" based in part on elevated capital expenditure programs that result in negative discretionary cash flows.[16] Support for LGE/KU's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

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[14] PPL Corporation 2019 Form 10-K Report at 62.

[15] Moody's Investors Service, *Louisville Gas & Electric Company*, Credit Opinion (Oct. 25, 2019); Moody's Investors Service, *Kentucky Utilities Company*, Credit Opinion (Oct. 25, 2019).

[16] S&P Global Ratings, *Louisville Gas & Electric Co.*, RatingsDirect (Mar. 16, 2020); S&P Global Ratings, *Kentucky Utilities Co.*, RatingsDirect (Mar. 20, 2020).

Q24. WHAT CREDIT RATINGS ARE ASSIGNED TO LGE/KU?

A24. Currently, LGE and KU are assigned corporate credit ratings of A- by S&P, while Moody's has assigned the Companies an issuer rating of A3.

B. Outlook for Capital Costs

Q25. PLEASE SUMMARIZE CURRENT ECONOMIC AND CAPITAL MARKET CONDITIONS.

A25. In the second quarter of 2020, U.S. real GDP growth declined sharply at 31.7%, following a decline of 0.5% in the prior quarter. The unemployment rate continued to fall gradually to 8.4% in August of 2020, from its peak at 14.7% in April, which is indicative of a frail but improving labor market and an economy that remains significantly below full employment. Inflation, as evidenced by the Consumer Price Index, was low at around 1.3% in August 2020. Investors continue to face volatility as capital markets respond to uncertainties surrounding the sharp decline in real economic output associated with the COVID-19 pandemic and related state and federal shutdowns, as well as the resulting economic stimulus packages that characterized the first half of 2020.

This underlying risk and unease has been felt worldwide as countries have struggled to manage the pandemic. China's GDP showed a sharp contraction in the first quarter of 2020, followed by tepid growth in the second quarter. The European Union evidenced sharp declines in GDP during the first and second quarters of 2020. Economic activity has remained weak in many emerging market economies, including Brazil and Mexico. The global economic contraction comes on top of already heightened geopolitical tensions in the Middle East, which in the past have led to ongoing concerns over possible disruptions in crude oil supplies and attendant price volatility.

Q26. HOW HAVE COMMON EQUITY MARKETS BEEN IMPACTED BY COVID-19?

A26. The threat posed by the coronavirus pandemic has led to extreme volatility in the capital markets as investors dramatically revise their risk perceptions and return requirements in the face of the severe disruptions to commerce and the world economy. Simultaneously, energy markets have been roiled by the threat to demand posed by a worldwide economic slowdown and a breakdown of Russia's partnership with the Organization of the Petroleum Exporting Countries ("OPEC"). These simultaneous demand and supply shocks have led to sharp declines in oil prices, which have further confounded investors and destabilized the economic outlook and asset prices.

Despite the actions of the world's central banks to ease market strains and bolster the economy, global financial markets have experienced extreme volatility and precipitous declines in asset values. On March 12, 2020, the Dow Jones Industrial Average ("DJIA") suffered its worst decline since the 1987 "Black Monday" crash, falling by almost 10 percent in a single session, and pushing the index into a bear market, defined as a 20 percent drop from a previous high. On March 16, 2020, the DJIA experienced its greatest fall, point-wise, in history, ending the day with a decline of 2,997 points. Similarly, between February 19 and March 23, 2020, the S&P 500 lost more than 30 percent of its total value. The Chicago Board Options Exchange Volatility Index (commonly known as the "VIX"), which is a key measure of expectations of near-term volatility and market sentiment, rose to levels not seen since the 2008-2009 financial crisis.

Q27. HAVE UTILITIES AND THEIR INVESTORS FACED SIMILAR TURMOIL?

A27. Yes. As of March 23, 2020, the Dow Jones Utility Average ("DJUA") had fallen approximately 36 percent from the previous high reached on February 18, 2020, demonstrating the fact that regulated utilities and their investors are not immune from the impact of financial market turmoil. As with the broader market, utility stock prices have recovered from these lows, but as of September 30, 2020, the DJUA remains 15 percent below its previous high. While equity markets have recovered from the lows reached in March 2020, the pronounced selloff and ongoing volatility evidences investors' trepidation to commit capital and marks a significant upward revision in their perceptions of risk and required returns.

Concerns over weakening credit quality prompted S&P to revise its outlook for the regulated utility industry from "stable" to "negative."[17] As S&P explained:

> Even before the current downturn and COVID-19, a confluence of factors, including the adverse impacts of tax reform, historically high capital spending, and associated increased debt, resulted in little cushion in ratings for unexpected operating challenges.[18]

While recognizing regulatory protections that should mitigate the impact of the coronavirus pandemic, S&P noted that "the timing and extent of these protections adds uncertainty to already stretched financial profiles."[19] S&P warned investors that pressure on utility finances "sets the stage for downgrades."[20] As S&P concluded, challenges posed by the coronavirus crisis "have the potential to significantly impact the financial performance of the investor-owned utilities, increasing the overall level of investor risk, and will have to be addressed by . . . regulators."[21]

Meanwhile Moody's noted that utilities were forced to seek alternatives to volatile commercial paper markets in order to fund operations and emphasized the

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[17] S&P Global Ratings, *COVID-10: The Outlook For North American Regulated Utilities Turns Negative*, RatingsDirect (Apr. 2, 2020).
[18] S&P Global Ratings, *North American Regulated Utilities Face Tough Financial Policy Tradeoffs To Avoid Ratings Pressure Amid The COVID-19 Pandemic*, RatingsDirect (May 11, 2020).
[19] *Id.*
[20] *Id.*
[21] S&P Global Market Intelligence, *State Regulatory Evaluations*, RRA Regulatory Focus (Mar. 25, 2020).

importance of maintaining adequate liquidity in the sector to weather a prolonged period of financial volatility and turbulent capital markets.[22] As Moody's concluded a recent utility credit review:

> The coronavirus outbreak, weak global economic outlook and asset price declines are creating a severe and extensive credit shock across many sectors, regions and markets. The combined credit effects of these developments are unprecedented.[23]

Q28. WHAT ACTIONS HAS THE FEDERAL RESERVE TAKEN IN RESPONSE TO THE THREAT TO THE ECONOMY POSED BY THE CORONAVIRUS PANDEMIC?

A28. In early 2020, the Federal Reserve quickly lowered its policy rate to close to zero to support economic activity, stabilize markets, and bolster the flow of credit to households, businesses, and communities. In March 2020, the Federal Reserve lowered the target range for its benchmark federal funds rate by a total of 150 basis points, to the current range of 0% to 0.25%. The Federal Open Market Committee expects to maintain this target range until it is confident that the economy has weathered recent events.

In addition, the Federal Reserve has announced a broad range of unprecedented programs designed to support financial market liquidity and economic stability. The quantitative easing ("QE") measures initially adopted in response to the 2008 financial crisis were reintroduced by directing the purchase of Treasury securities and agency mortgage-backed securities "in the amounts needed to support the smooth functioning of markets,"[24] while continuing to reinvest all principal

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[22] Moody's Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).

[23] Moody's Investors Service, *Moody's assigns Baa3 rating to Pacific Gas & Electric's first mortgage bonds and B1 rating to PG&E Corp's senior secured debt; outlooks stable*, Rating Action (Jun. 15, 2020).

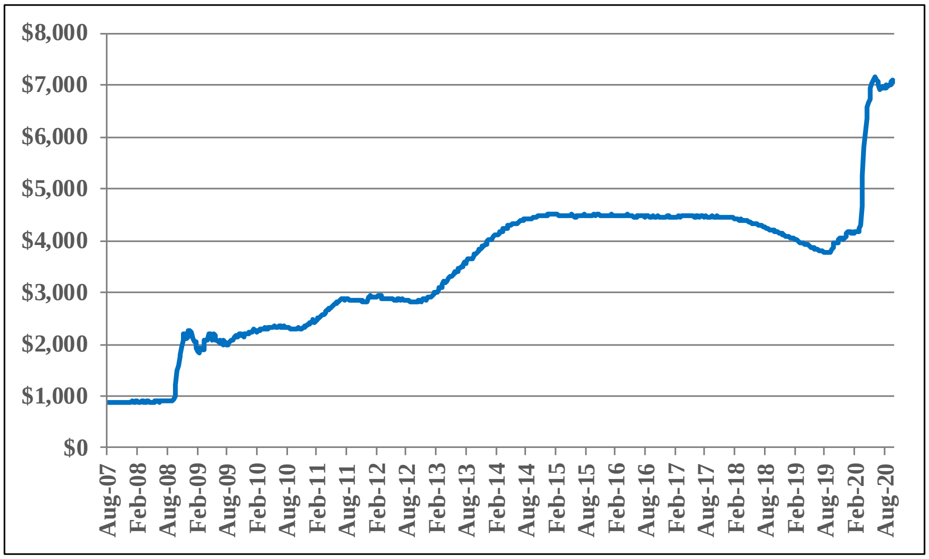
[24] Federal Reserve, *Press Release* (Mar. 23, 2020). https://www.federalreserve.gov/monetarypolicy/files/monetary20200323a1.pdf.

payments from its existing holdings. In addition, the Federal Reserve has also announced wide-raging initiatives designed to support credit markets and ensure liquidity, including credit facilities to support households, businesses, and state and local governments, as well as the purchase of corporate bonds on the secondary market.[25]

As illustrated below, the Federal Reserve's asset holdings exceed $7 trillion, which is an all-time high, and the resulting effect on capital market conditions has likely never been more pronounced. While the Federal Reserve's aggressive monetary stimulus may help to ensure market liquidity and support the economy, these actions also support financial asset prices, which in turn place artificial downward pressure on bond yields.

[25] *See, e.g., Federal Reserve takes additional actions to provide up to $2.3 trillion in loans to support the economy*, Press Release (Apr. 9, 2020). https://www.federalreserve.gov/newsevents/pressreleases/monetary20200409a.htm.

FIGURE 1
FEDERAL RESERVE BALANCE SHEET
(BILLION $)



https://fred.stlouisfed.org/series/WALCL

Q29. DO TRENDS IN THE YIELDS ON TREASURY NOTES AND BONDS ACCURATELY REFLECT THE EXPECTATIONS AND REQUIREMENTS OF THE COMPANIES' EQUITY INVESTORS?

A29. No. While Treasury bond yields provide one indicator of capital costs, they do not serve as a direct guide to the magnitude—or even direction—for changes in the cost of equity for utilities. For example, during times of heightened uncertainty and risk, investors may prefer the relative safety of U.S. government bonds, which can lead to a significant fall in Treasury bond yields at the same time that required returns on common stocks are increasing. Treasury bond yields may also be disproportionally impacted by monetary policies, such as QE, designed with the express intent of artificially suppressing bond yields. FERC has recognized that movements in Treasury bond yields do not provide a reliable guide to changes in required returns for utilities, concluding that "adjusting ROEs based on changes in U.S. Treasury bond yields may not produce a rational result, as both the magnitude and direction of the correlation may be inaccurate."[26]

Q30. DOES THE PROSPECT OF ECONOMIC RECESSION IMPLY LOWER CAPITAL COSTS?

A30. No. Investors' required rates of return for LGE/KU and other financial assets are a function of risk, with greater exposure to uncertainty requiring higher—not lower—rates of return to induce long-term investment. With respect to credit markets, S&P observed that conditions "look set to remain extraordinarily difficult for borrowers at least into the second half of the year, with the economic stop associated with coronavirus-containment measures continuing with no clear end in sight."[27] And while regulated utilities are favorably positioned relative to other industry sectors, S&P nevertheless noted that "access to the equity markets remains extraordinarily challenging."[28]

While expected growth rates may moderate as the economy softens, it is important not to confuse investors' expectations for future growth with their required rate of return. In fact, trends in growth rates say nothing at all about investors' overall risk perceptions. The fact that investors' required rates of return for long-term capital can rise in tandem with expectations of declining growth that might accompany an economic slowdown is demonstrated in the equity markets, where perceptions of greater risks led investors to sharply reevaluate what they are willing to pay for common stocks. While the decline in utility stock prices may in part be attributed to somewhat diminished expectations of future cash flows, there is also every indication

[26] *Coakley v. Bangor Hydro-Elec.,* 147 FERC ¶ 61,234 at P 159 (2014).

[27] S&P Global Ratings, *Credit Conditions North America: Unprecedented Uncertainty Slams Credit* (Mar. 31, 2020).

[28] S&P Global Ratings, *COVID-19: The Outlook For North American Regulated Utilities Turns Negative,* RatingsDirect (Apr. 2, 2020).

that investors' discount rate, or cost of common equity, has moved significantly higher to accommodate the greater risks they now associate with equity investments.

Q31. DO CHANGES IN UTILITY COMPANY BETA VALUES SINCE THE PANDEMIC BEGAN CORROBORATE AN INCREASE IN INDUSTRY RISK?

A31. Yes. As noted earlier, beta is used by the investment community as an important guide to investors' risk perceptions. As shown in Table 1 as part of my response to Q39 below, the current average beta for the proxy group of comparable utilities I rely on in this case for estimating the Companies' ROE is 0.87. The beta value corresponding to LGE/KU is 1.10. Prior to the pandemic, the average beta for the same group of companies was 0.56 and the beta corresponding to LGE/KU was 0.70. This dramatic increase in a primary gauge of investors' risk perceptions is further proof of the rise in electric utility risk in 2020.

Q32. WOULD IT BE REASONABLE TO DISREGARD THE IMPLICATIONS OF CURRENT CAPITAL MARKET CONDITIONS IN ESTABLISHING A FAIR ROE FOR LGE/KU?

A32. No. They reflect the reality of the situation in which LGE/KU and other businesses must attract and retain capital. The standards underlying a fair rate of return require that the Companies' authorized ROE reflect a return competitive with other investments of comparable risk and preserve their ability to maintain access to capital on reasonable terms. These standards can only be met by considering the requirements of investors in today's capital markets. As S&P concluded, challenges posed by the coronavirus crisis "have the potential to significantly impact the financial performance of the investor-owned utilities, increasing the overall level of investor risk, and will have to be addressed by state regulators."[29]

While market dislocations may complicate the evaluation of the cost of common equity, there has been little indication that the challenges confronting the economy and financial markets will be resolved quickly. If the increase in investors' required rate of return is not incorporated in the allowed ROE, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. From a more practical perspective, failing to provide investors with the opportunity to earn a rate of return commensurate with LGE/KU's risks will only serve to weaken financial integrity, while hampering the Companies' ability to attract the capital needed to meet the economic and reliability needs of their service area.

Q33. MIGHT THE ECONOMIC DISLOCATIONS CAUSED BY THE CORONAVIRUS PANDEMIC BE TEMPORARY?

A33. No one knows the future of our complex global economy. While there is continued hope for a swift economic rebound as COVID-19 containment measures are gradually lifted, residual impacts of the unprecedented economic and health crisis could linger indefinitely. In any event, it would be imprudent to gamble the interests of customers and the economy of Kentucky in the hope that the harsh economic reality will suddenly be resolved. LGE/KU must raise capital in the real world of financial markets. To ignore the current reality would be unwise given the importance of reliable utility service for customers and the economy.

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[29] S&P Global Market Intelligence, *State Regulatory Evaluations*, RRA Regulatory Focus (Mar. 25, 2020).

IV. COMPARABLE RISK PROXY GROUP

Q34. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A34. This section describes the procedures underlying my identification of a proxy group of publicly traded companies.

A. Evaluation of Proxy Group

Q35. CAN QUANTITATIVE METHODS BE APPLIED DIRECTLY TO LGE/KU TO ESTIMATE THE COST OF EQUITY?

A35. No. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q36. HOW DO YOU IDENTIFY THE PROXY GROUP OF ELECTRIC UTILITIES RELIED ON FOR YOUR ANALYSES?

A36. In order to reflect the risks and prospects associated with LGE/KU's jurisdictional utility operations, my analyses initially focused on a reference group of other utilities composed of those companies in Value Line's electric utility industry groups with:

1. Both electric and gas utility operations.
2. No ongoing involvement in a major merger or acquisition.
3. No cuts in dividend payments during the past six months and no announcement of a dividend cut since that time.

In addition, my analysis also considered credit ratings from S&P and Moody's, along with Value Line's Safety Rank in evaluating relative risk.

Specifically, I limited the proxy group to those companies with ratings that fall within two "notches" higher or lower than the A- corporate credit rating assigned to LGE/KU by S&P, which results in a ratings range of BBB to A+. Meanwhile, considering the long term issuer rating of A3 rating assigned to the Companies by Moody's, I limited the proxy group to include only those utilities with a Moody's ratings in the range of Baa2 to A1. Finally, I excluded utilities with a Value Line Safety Rank below "2."

Q37. WHAT OTHER PUBLICLY TRADED UTILITY IS RELEVANT IN EVALUATING A PROXY GROUP FOR LGE/KU?

A37. Although it has not yet been included in Value Line's electric utility industry groups, it is reasonable to expect that investors would also regard Algonquin Power & Utilities, Inc. ("Algonquin") as having operations comparable to those of other electric utilities in the proxy group. Algonquin is a North American diversified generation, transmission, and distribution utility with approximately $10 billion in total assets. Algonquin provides regulated utility services to over 782,000 customers in California, Iowa, Illinois, Missouri, Montana, Arkansas, Georgia, and Texas. Algonquin completed its acquisition of Empire District Electric Company ("Empire District") on January 1, 2017. Empire District was included in Value Line's electric utility industry group prior to its merger with Algonquin. Therefore, it would be reasonable for investors to regard Algonquin as a comparable investment alternative that is relevant to an evaluation of the required rate of return for LGE/KU. While Algonquin is not rated by Moody's, it has been assigned a credit rating of BBB by S&P, which falls within the screening criterion outlined above.

B. Relative Risks of the Proxy Group and LGE/KU

Q38. HOW DO YOU EVALUATE THE RISKS OF THE UTILITY GROUP RELATIVE TO LGE/KU?

A38. My evaluation of relative risk considers four objective, published benchmarks that are widely relied on in the investment community. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide broad, objective measures of overall investment risk that are readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in my experience Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[30]

Q39. HOW DO THE OVERALL RISKS OF YOUR PROXY GROUP COMPARE TO LGE/KU?

A39. Table 1 compares the Utility Group with LGE/KU across the four key indices of investment risk discussed above. Because the Companies have no publicly traded common stock, the Value Line risk measures shown reflect those published for their ultimate parent, PPL:

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[30] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 71.

TABLE 1
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Utility Group	BBB+	Baa2	2	A	0.87
LGE/KU	A-	A3	2	B++	1.10

Q40. WHAT DOES THIS COMPARISON INDICATE REGARDING INVESTORS' ASSESSMENT OF THE RELATIVE RISKS ASSOCIATED WITH YOUR UTILITY GROUP?

A40. As shown above, LGE/KU's credit ratings are above the average for the utility group, which suggests somewhat less risk. Meanwhile, the Safety Rank corresponding to the Companies is identical to the average for the Utility Group, while the Financial Strength Rating and beta value suggest greater risk for LGE/KU than for the Utility Group. Considered together, this comparison of objective measures, which incorporate a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for LGE/KU are comparable to those of the firms in the Utility Group.

Q41. DO YOU CONSIDER THE IMPLICATIONS OF COST RECOVERY MECHANISMS IN EVALUATING A FAIR ROE FOR LGE/KU?

A41. Yes. Adjustment mechanisms, cost trackers, and future test years have become increasingly prevalent in the utility industry in recent years, along with alternatives to traditional ratemaking such as formula rates. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers through a variety of adjustment mechanisms. Based largely on the expanded use of ratemaking mechanisms to address operational risks and investment recovery, Moody's upgraded most regulated utilities in January 2014.[31] This is consistent with the view that investors perceive the impact of regulatory mechanisms to have an across-the-board impact on risk perceptions for virtually all utilities.

Reflective of this trend, companies in the electric utility industry operate under a wide variety of cost adjustment mechanisms, in addition to the standard fuel cost recovery clauses that they all have. These enhanced tools encompass revenue decoupling and adjustment clauses designed to address capital investment outside of a traditional rate case, as well as riders to recover environmental compliance costs, bad debt expenses, certain taxes and fees, and post-retirement employee benefit costs. *RRA Regulatory Focus* concluded in its most recent review of adjustment clauses that:

> More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation capacity or delivery infrastructure to be reflected in rates, effectively including these items in rate base without a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress.
>
> [C]ertain types of adjustment clauses are more prevalent than others. For example, those that address electric and fuel and gas commodity charges are in place in all jurisdictions. Also, about two-thirds of all utilities have riders in place to recover costs related to energy efficiency programs, and roughly half of the utilities utilize some type of decoupling mechanism.[32]

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[31] Moody's Investors Service, *US utility sector upgrades driven by stable and transparent regulatory frameworks*, Sector Comment (Feb. 3, 2014).
[32] S&P Global Market Intelligence, *Adjustment Clauses, A State-by-State Overview*, RRA Regulatory Focus (Nov. 12, 2019).

Q42. HAVE SIMILAR REGULATORY MECHANISMS BEEN APPROVED FOR LGE/KU?

A42. Yes. In addition to a fuel adjustment clause, Kentucky Revised Statute 278.183 notes, in part, that "a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal." Consistent with this statutory provision, the KPSC has approved an environmental cost recovery mechanism ("ECR") for the Companies that allows for recovery of related costs. In addition, LGE/KU also operate under a Demand Side Management ("DSM") rate mechanism that provides for recovery of DSM costs, including a provision to earn a return of and on capital investment for DSM programs. In addition, LGE utilizes a KPSC-approved weather normalization adjustment ("WNA") that partially adjusts natural gas utility revenues for the effect of weather extremes by accounting for differences in consumption due to deviations from normal weather patterns during the heating season months of November through April. The KPSC has also approved a gas line tracker mechanism for LGE that allows for recovery of costs associated with gas infrastructure improvements.

Q43. DOES THE FACT THAT LGE/KU OPERATE UNDER CERTAIN REGULATORY MECHANISMS WARRANT ANY ADJUSTMENT IN YOUR EVALUATION OF A FAIR ROE?

A43. No. Investors recognize that the Companies are exposed to significant risks associated with the ability to recover rising costs and investment on a timely basis, and concerns over these risks have become increasingly pronounced in the industry. The KPSC's rate adjustment mechanisms are a tool to address these risks, but they do not eliminate them. In addition, investors also recognize that the periodic reviews associated with trackers expose LGE/KU to an increased risk of disallowances.

While the regulatory mechanisms approved for LGE/KU partially attenuate exposure to attrition in an era of rising costs and investment, this leveling of the playing field only serves to address factors that could otherwise impair the Companies' opportunity to earn their authorized return. Similarly, LGE/KU's election to employ a future test year is supportive of the Companies' financial integrity, but it does not constitute a dramatic change in the Companies' investment risk relative to other firms in the industry.

Q44. DO THESE MECHANISMS DISTINGUISH LGE/KU FROM OTHER UTILITIES?

A44. No. Many adjustment mechanisms are also available to the companies in my proxy group of utilities. As summarized on page 1 of Exhibit No. 3, these mechanisms are ubiquitous and wide ranging. For example, twelve of the nineteen utilities benefit from mechanisms that permit cost recovery of infrastructure investment outside a formal rate proceeding. Thirteen of these utilities operate under full or partial revenue decoupling mechanisms that insulate the utility from volatility related to fluctuations in sales volumes. Adjustment clauses to reflect changes in a diverse range of operating and capital costs, including expenditures related to environmental mandates, conservation programs, transmission costs, and storm recovery efforts are also widespread.

Q45. IS THE USE OF A FUTURE TEST YEAR ALSO A COMMON FEATURE ON THE REGULATORY LANDSCAPE?

A45. Yes. With respect to future test years, a 2015 study by the Edison Electric Institute concluded that "the ranks of US jurisdictions that allow the use of forward test years have swollen and now encompass about half of the total."[33] With respect to the nineteen firms in the Utility Group, eighteen operate in jurisdictions that allow for the use of a forward-looking test year. LGE/KU's election to use a future test year is consistent with state statute and the treatment afforded other utilities operating in Kentucky, and it does not distinguish the Companies from other utilities across the nation.

Q46. WHAT IS YOUR CONCLUSION REGARDING THE IMPACT OF REGULATORY MECHANISMS IN EVALUATING A FAIR ROE FOR LGE/KU?

A46. Investors recognize that the use of adjustment mechanisms and future test years is widely prevalent in the utility industry, and the relative impact is already considered in the data for my proxy group. As a result, any mitigation in risks associated with LGE/KU's ability to attenuate regulatory lag through adjustment mechanisms or election of a future test year is already reflected in the results of the quantitative methods presented in my testimony. The KPSC's adjustment mechanisms and LGE/KU's election to use a future test year act to level the playing field, placing the Companies on equal footing with their industry peers. As a result, no adjustment to the ROE is justified or warranted.

V. CAPITAL MARKET ANALYSES AND ESTIMATES

Q47. WHAT IS THE PURPOSE OF THIS SECTION?

A47. This section presents capital market estimates of the cost of equity. First, I discuss the current outlook for capital costs. I then address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets.

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[33] *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute (Nov. 11, 2015).

Next, I describe various quantitative analyses conducted to estimate the cost of common equity for the proxy group of comparable risk firms. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

C. Economic Standards

Q48. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A48. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q49. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A49. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q50. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A50. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q51. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A51. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q52. DOES THE FACT THAT LGE/KU ARE ULTIMATELY SUBSIDIARIES OF PPL IN ANY WAY ALTER THESE FUNDAMENTAL STANDARDS UNDERLYING A FAIR ROE?

A52. No. While LGE/KU have no publicly traded common stock and PPL is ultimately their only shareholder, this does not change the standards governing the determination of a fair ROE for the Companies. The common equity that is required to support the utility operations of LGE/KU must be raised by PPL in the capital markets, where investors consider the Companies' ability to offer a rate of return that is competitive with other risk-comparable alternatives. Unless there is a reasonable expectation that the Companies can earn a return that is commensurate with the underlying risks, capital will be allocated elsewhere, LGE/KU's financial integrity will be weakened, and investors will demand an even higher rate of return. LGE/KU's ability to offer a reasonable return on investment is a necessary ingredient in ensuring that customers continue to enjoy economical rates and reliable service.

Q53. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF COMMON EQUITY FOR A UTILITY?

A53. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

D. Discounted Cash Flow Analyses

Q54. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A54. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[34]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;

D_1 = Expected dividend per share in the coming year;

k_e = Cost of equity; and,

g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

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[34] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (*g*). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q55. WHAT STEPS ARE REQUIRED TO APPLY THE CONSTANT GROWTH DCF MODEL?

A55. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (*g*) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q56. HOW DID YOU DETERMINE THE DIVIDEND YIELD FOR THE UTILITY GROUP?

A56. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Utility Group are presented on page 1 of Exhibit No. 4. As shown there, dividend yields for the firms in the Utility Group ranged from 2.5% to 4.9%.

Q57. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A57. The next step is to evaluate growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q58. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A58. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks and capital requirements in the industry, with the payout ratios falling significantly from historical levels. As a result, dividend growth in the utility industry has lagged growth in earnings as utilities conserve financial resources.

A measure that plays a pivotal role in determining investors' long-term growth expectations are future trends in EPS, which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS").

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q59. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A59. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q60. DID PROFESSOR MYRON J. GORDON, WHO ORIGINATED THE DCF APPROACH, RECOGNIZE THE PIVOTAL ROLE THAT EARNINGS PLAY IN FORMING INVESTORS' EXPECTATIONS?

A60. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[35]

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[35] Myron J. Gordon, *The Cost of Capital to a Public Utility*, MSU Pub. Util. Studies at 89 (1974).

Q61. ARE ANALYSTS' ASSESSMENTS OF GROWTH RATES APPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A61. Yes. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications, as well as the continued success of services such as Thomson Reuters and Value Line, implies that investors use them as a basis for their expectations.

While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. <u>The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations</u>.[36]

Q62. HAVE REGULATORS ALSO RECOGNIZED THAT ANALYSTS' GROWTH RATE ESTIMATES ARE AN IMPORTANT AND MEANINGFUL GUIDE TO INVESTORS' EXPECTATIONS?

A62. Yes. The KPSC has indicated its preference for relying on analysts' projections in establishing investors' expectations:

> KU's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance ….[37]

Similarly, FERC has expressed a clear preference for projected EPS growth rates from IBES in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities:

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients

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[36] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 298 (emphasis added).

[37] *Application of Kentucky Utilities Company for an Adjustment of Base* Rates, Case No. 2009-00548, Order at 30-31 (Ky. P.S.C. July 30, 2010).

> since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[38]

The Public Utility Regulatory Authority of Connecticut has also noted that "there is not growth in DPS without growth in EPS," and concluded that securities analysts' growth projections have a greater influence over investors' expectations and stock prices.[39] In addition, the Regulatory Commission of Alaska ("RCA") has previously determined that analysts' EPS growth rates provide a superior basis on which to estimate investors' expectations:

> We also find persuasive the testimony . . . that projected EPS returns are more indicative of investor expectations of dividend growth than historical growth data because persons making the forecasts already consider the historical numbers in their analyses.[40]

The RCA has concluded that arguments against exclusive reliance on analysts' EPS growth rates to apply the DCF model "are not convincing."[41]

Q63. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY GROUP?

A63. The earnings growth projections for each of the firms in the Utility Group reported by Value Line, IBES, and Zacks are displayed on page 2 of Exhibit No. 4.

Q64. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A64. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio

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[38] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034at P 121 (2009) (footnote omitted).
[39] *Decision*, Docket No. 13-02-20 (Sept. 24, 2013).
[40] Regulatory Commission of Alaska, U-07-76(8) at 65, n. 258.
[41] Regulatory Commission of Alaska, U-08-157(10) at 36.

are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the Utility Group are summarized on page 2 of Exhibit No. 4, with the underlying details being presented on Exhibit No. 5.[42]

Q65. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE "BR+SV" GROWTH RATE?

A65. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[43] The "sustainable growth" approach was included for completeness, but evidence indicates

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[42] Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, which is consistent with the theory underlying this approach.
[43] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 307.

that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

Q66. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE UTILITY GROUP USING THE DCF MODEL?

A66. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit No. 4.

Q67. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A67. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q68. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A68. I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q69. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A69. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[44] FERC affirmed that:

> The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt. In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test.[45]

Q70. WHAT INTEREST RATE BENCHMARK DID YOU CONSIDER IN EVALUATING THE DCF RESULTS FOR THE UTILITY GROUP?

A70. Utility bonds rated "Baa" represent the lowest ratings grade for which Moody's publishes index values, and the closest available approximation for the risks of common stock, which are significantly greater than those of long-term debt. The average of Moody's monthly yields for Baa utility bonds was 3.37% over the six months ended September 2020.[46]

Q71. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A71. Current forecasts continue to anticipate higher long-term rates over the near-term. As shown in Table 2 below, forecasts of IHS Markit and the Energy Information

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[44] *See, e.g., Southern California Edison Co.,* 131 FERC ¶ 61,020 at P 55 (2010).
[45] Opinion No. 531, 147 FERC ¶ 61,234 at P 122 (2014).
[46] Moody's Investors Service, *CreditTrends.*

Administration ("EIA") imply an average triple-B bond yield of approximately 4.8% over the period 2021-2025:

TABLE 2
IMPLIED BAA BOND YIELD

	Baa Yield 2021-25
Projected Aa Utility Yield	
IHS Global Insight (a)	3.65%
EIA (b)	4.60%
Average	4.12%
Current Baa - AA Yield Spread (c)	0.67%
Implied Baa Utility Yield	**4.79%**

(a) IHS Markit, Long-Term Macro Forecast - Baseline (May 28, 2020).
(b) Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Apr. - Sep. 2020.

Q72. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A72. The premium that investors demand to bear the higher risks of common stock is not constant. As demonstrated empirically in the application of the risk premium method,[47] equity risk premiums expand when interest rates fall, and vice versa.

For example, based on a review of its precedent for evaluating low-end values, FERC established a 100 basis point risk premium over Moody's bond yield averages as a threshold to eliminate DCF results in *SoCal Edison*, citing prior decisions in

[47] Exhibit No. 8, page 4.

Atlantic Path 15,[48] *Startrans*,[49] and *Pioneer*[50] in support of this policy.[51] Because bond yields declined significantly between the time of those findings and the study period in this case, the inverse relationship implies a significant increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds.

As shown on page 4 of Exhibit No. 4, recognizing the inverse relationship between equity risk premiums and bond yields would indicate a current low-end threshold in the range of approximately 5.8% to 6.6%. The impact of widening equity risk premiums should be considered in evaluating low-end cost of equity estimates. FERC's more recent methodology based on the CAPM market risk premium indicates a low-end threshold of 5.4%.

Q73. WHAT DO YOU CONCLUDE REGARDING THE REASONABLENESS OF DCF VALUES AT THE LOW END OF THE RANGE OF RESULTS?

A73. As highlighted on page 3 of Exhibit No. 4, after considering these tests and the distribution of individual estimates, I eliminate six low-end DCF estimates ranging from 4.9% to 6.4%. Based on my professional experience and the risk-return tradeoff principle that is fundamental to finance, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. As a result, consistent with the threshold established by historical and projected utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

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[48] *Atl. Path 15, LLC*, 122 FERC ¶ 61,135 (2008) ("*Atlantic Path 15*").
[49] *Startrans IO, LLC*, 122 FERC ¶ 61,306 (2008) ("*Startrans*").
[50] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009) ("*Pioneer*").
[51] *SoCal Edison* at P 54.

Q74. DO YOU ALSO RECOMMEND EXCLUDING ESTIMATES AT THE HIGH END OF THE RANGE OF DCF RESULTS?

A74. While I typically recommend the exclusion of high end estimates that are clearly implausible, in this case, no such values exist. The upper end of the DCF range for the Utility Group is set by a cost of equity estimate of 13.6%. While a 13.6% cost of equity estimate may exceed the majority of the remaining values, low-end DCF estimates in the 6.7% to 7.2% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

Q75. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY GROUP?

A75. As shown on page 3 of Exhibit No. 4 and summarized in Table 3, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following average cost of common equity estimates:

TABLE 3
DCF RESULTS – UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	8.8%	10.2%
IBES	9.2%	9.3%
Zacks	9.1%	9.7%
br + sv	8.3%	8.9%

E. Capital Asset Pricing Model

Q76. PLEASE DESCRIBE THE CAPM.

A76. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q77. WHY IS THE CAPM APPROACH A RELEVANT COMPONENT WHEN EVALUATING THE COST OF EQUITY FOR LGE/KU?

A77. The CAPM approach (which also forms the foundation of the ECAPM) generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere, the CAPM (and ECAPM) provides important insight into investors' required rate of return for utility stocks, including LGE/KU.

Q78. HOW DO YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A78. Application of the CAPM to the Utility Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. 6. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return is estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm is obtained from Value Line, and the growth rate is equal to the average of the earnings growth projections for each firm published by Value Line, IBES and Zacks, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the individual firms, current estimates imply an average growth rate over the next five years of 9.2%. Combining this average growth rate with a year-ahead dividend yield of 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 11.6%. Subtracting a 1.4% risk-free rate based on the average yield on 30-year Treasury bonds for the six months ending September 2020 produces a market equity risk premium of 10.2%.

Q79. WHAT IS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A79. As indicated earlier in my discussion of risk measures for the Utility Group, I rely on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

Q80. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A80. Financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. Accordingly, a modification is required to account for this size effect. As explained by *Morningstar*:

> One of the most remarkable discoveries of modern finance is that of a relationship between company size and return. … The relationship between company size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks. … This size-rated phenomenon has prompted a revision to the CAPM, which includes a size premium.[52]

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, researchers have developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[53] Accordingly, my CAPM analysis also incorporates an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Utility Group.

Q81. ARE YOU RECOMMENDING THAT THE KPSC AWARD LGE/KU A PREMIUM TO THE ROE BECAUSE OF THEIR SIZE?

A81. Absolutely not. I am not proposing to apply a general size risk premium in evaluating a fair and reasonable ROE for LGE/KU and my recommendation does not include any adjustment related to the Companies' size. Rather, the size adjustment is specific

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[52] Morningstar, *Ibbotson SBBI 2015 Classic Yearbook* at pp. 99, 108.

[53] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, "Stocks, Bonds, Bills and Inflation," these size premia are now developed by Duff & Phelps.

to the CAPM and merely corrects for an observed inability of the beta measure to fully reflect the risks perceived by investors for the firms in the Utility Group. As FERC has recognized, "This type of size adjustment is a generally accepted approach to CAPM analyses."[54]

Q82. WHAT IS THE IMPLIED ROE FOR THE UTILITY GROUP USING THE CAPM APPROACH?

A82. As shown on Exhibit No. 6, after adjusting for the impact of firm size, the CAPM approach implies an average and midpoint cost of equity of 10.7% for the Utility Group.

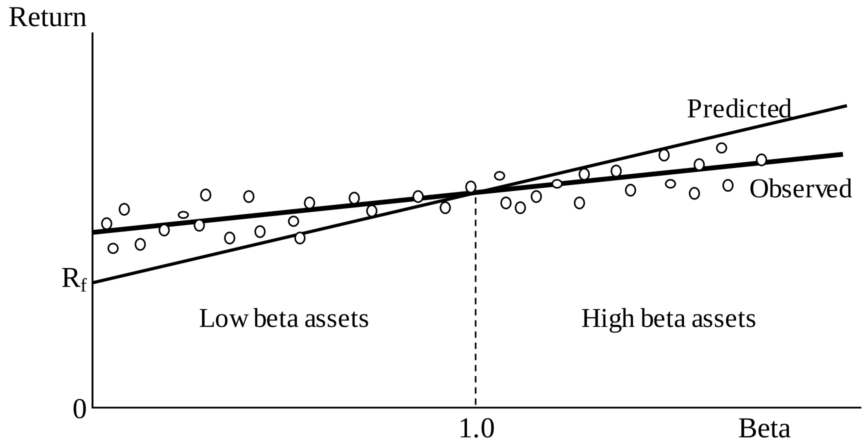
F. Empirical Capital Asset Pricing Model

Q83. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A83. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower returns than predicted by the CAPM. This is illustrated graphically in the figure below:

[54] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117 (2015).

FIGURE 2
CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the Utility Group, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[55]

As discussed in *New Regulatory Finance*, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

Like the CAPM formula presented earlier, the ECAPM represents a stock's required return as a function of the risk-free rate (R_f), plus a risk premium. In the formula above, this risk premium is composed of two parts: (1) the market risk

[55] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports at 189 (2006).

premium (R_m - R_f) weighted by a factor of 25%, and (2) a company-specific risk premium based on the stocks relative volatility [(β)(R_m - R_f)] weighted by 75%. This ECAPM equation, and its associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q84. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF VALUE LINE BETAS?

A84. Yes. Value Line beta values are adjusted for the observed tendency of beta to converge toward the mean value of 1.00 over time.[56] The purpose of this adjustment is to refine beta values determined using historical data to better match forward-looking estimates of beta, which are the relevant parameter in applying the CAPM or ECAPM models. Meanwhile, the ECAPM does not involve any adjustment to beta whatsoever. Rather, it represents a formal recognition of findings in the financial literature that the observed risk-return tradeoff illustrated in Figure 2 is flatter than predicted by the CAPM. In other words, even if a firm's beta value were estimated with perfect precision, the CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks. The ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns.

Q85. HAVE OTHER REGULATORS RELIED ON THE ECAPM?

A85. Yes. The staff of the Public Utilities Commission of Colorado has recognized, "The ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[57] and relied on the exact same standard

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[56] *See, e.g.,* Marshall E. Blume, *Betas and Their Regression Tendencies*, Journal of Finance, Vol. 30, No. 3 (Jun. 1975) at 785-795.

[57] Proceeding No. 13AL-0067G, *Answer Testimony and Attachments of Scott England* (July 31, 2013) at 47.

ECAPM equation presented above.[58] The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has relied on this same ECAPM formula in estimating the cost of equity for a natural gas utility,[59] as have witnesses for the Office of Arkansas Attorney General.[60]

The ECAPM approach has been relied on by the Staff of the Maryland Public Service Commission. For example, Staff witness Julie McKenna noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[61] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[62]

More recently, the Montana Public Service Commission determined that "[t]he evidence in this proceeding has convinced the Commission that the Empirical Capital Asset Pricing Model ("ECAPM") should be the primary method for estimating . . . the cost of equity" for a gas distribution utility under its jurisdiction.[63]

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[58] *Id.* at 48.
[59] Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53.
[60] Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53; Docket No. 17-071-U, *Direct Testimony of Marlon F. Griffing, PH.D.* (May 29, 2018) at 33-35.
[61] *Direct Testimony and Exhibits of Julie McKenna*, Maryland PSC Case No. 9299 (Oct. 12, 2012) at 9.
[62] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002) at 145.
[63] Montana Public Service Commission, Docket No. D2017.9.80, Order No. 7575c (Sep. 26, 2018) at P 114.

Q86. WHAT COST OF EQUITY ESTIMATE IS INDICATED BY THE ECAPM?

A86. My application of the ECAPM is based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connection with the CAPM. As shown on Exhibit No. 7, applying the forward-looking ECAPM approach to the firms in the Utility Group results in an average cost of equity estimate of 11.0% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.[64]

G. Utility Risk Premium

Q87. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A87. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q88. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A88. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely

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[64] The midpoint of the size adjusted ECAPM range is also 11.4%.

referenced by the investment community and in academia and regulatory proceedings, and it provides an important tool in estimating a fair ROE for LGE/KU.

Q89. HOW DO YOU IMPLEMENT THE RISK PREMIUM METHOD?

A89. Estimates of equity risk premiums for utilities are based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q90. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR LGE/KU?

A90. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (*e.g.*, stock prices dividends, beta, and interest rates) and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q91. HOW DO YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A91. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit No. 8, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2019.[65] As shown on page 3 of Exhibit No. 8, over this period, these equity risk premiums for electric utilities averaged 3.76%, and the yield on public utility bonds averaged 8.10%.

Q92. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A92. Yes. The magnitude of equity risk premiums is not constant and equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall some fraction of 1%. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

As noted earlier, bond yields are at low levels. Given that equity risk premiums move inversely with interest rates, these uncharacteristically low bond yields also imply a sharp increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

[65] My analysis encompasses the entire period for which published data is available.

Q93. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A93. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. For example, *New Regulatory Finance* documented this inverse relationship:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[66]

Other regulators have also recognized that, while the cost of equity trends in the same direction as interest rates, these variables do not move in lock-step because of the inverse relationship between equity risk premiums and interest rates.[67] This relationship is illustrated in the figure on page 4 of Exhibit No. 8.

Q94. WHAT COST OF EQUITY IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED ROES?

A94. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit No. 8, the equity risk premium for electric utilities increased approximately 42 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit No. 8, with an

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[66] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 128.

[67] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-7, https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwiLs4Sy67nsAhVKHqwKHddgA1wQFjABegQIBRAC&url=https%3A%2F%2Fcdn.entergy-mississippi.com%2Fuserfiles%2Fcontent%2Fprice%2Ftariffs%2Feml_frp.pdf&usg=AOvVaw1vyc6J_1IccZshzpfCtD0v (last visited Oct. 16, 2020); Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (2014).

average yield on public utility bonds for the six-months ending September 2020 of 3.79%, this implies a current equity risk premium of 5.90% for electric utilities. Adding this equity risk premium to the average yield on Baa utility bonds of 3.37% implies a current cost of equity of 9.27%.

Q95. WHAT COST OF EQUITY ESTIMATE IS PRODUCED BY THE RISK PREMIUM APPROACH AFTER INCORPORATING FORECASTED BOND YIELDS?

A95. As note earlier, widely cited forecasts indicate that utility bond yields will increase over the period when the rates established in this proceeding will be in effect. This is documented in Table 4 below, which compares current interest rates on 10-year and 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with the average of near-term projections from Blue Chip Financial Forecasts, EIA, IHS Markit, and Value Line:

TABLE 4
INTEREST RATE TRENDS

	Sep. 2020	Average 2021-25	Change Basis Pts
10-Yr. Treasury	0.7%	1.9%	123
30-Yr. Treasury	1.4%	2.2%	82
Aaa Corporate	2.3%	3.0%	72
Aa Utility	2.6%	4.1%	150

Sources:
Moody's Investors Service.
https://fred.stlouisfed.org/.
Value Line Investment Survey, Forecast for the U.S. Economy (Aug. 28, 2020).
IHS Markit, Long-Term Macro Forecast - Baseline (Jun. 29, 2020).
Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020).
Wolters Kluwer, Blue Chip Financial Forecasts (Jun. 1, 2020).

Accordingly, in addition to the use of current bond yields, I also applied the risk premium approach based on a forecasted yield for 2021-2025.

As shown on page 2 of Exhibit No. 8, incorporating a forecasted yield for 2021-2025 and adjusting for changes in interest rates since the study period implied an equity risk premium of 5.43% for electric utilities. Adding this equity risk premium to the implied average yield on Baa public utility bonds for 2021-2025 of 4.79% resulted in an implied cost of equity of 10.22%.

Q96. THE EQUITY RISK PREMIUMS CALCULATED IN YOUR STUDY WERE BASED ON AUTHORIZED ROES PUBLISHED BY RRA. WOULD IT NOT BE EQUALLY APPROPRIATE TO USE RECENT VALUES COMPILED BY RRA TO ESTABLISH LGE/KU'S ROE DIRECTLY?

A96. No, it would not. While data on allowed returns published by RRA can have a role in evaluating a fair and reasonable ROE, there is no basis to place undue weight on a single, summary statistic in lieu of comprehensive analyses and a case-specific evidentiary record. Most importantly, such an approach fails to satisfy the standards mandated by the U.S. Supreme Court in its *Bluefield* and *Hope* decisions, which dictate that the ROE reflect contemporaneous returns to investments of comparable risk.

These bedrock opinions require regulators to consider the individual and specific risks and financial circumstances facing the utility, as well as the capital market conditions and investor expectations concurrent with their deliberations. Meeting these standards necessitates detailed analyses and the application of financial models and approaches with inputs that are specific to the utility in question. In a rate-case context, alternative analyses and expert opinions are subject to thorough discovery and cross examination from all stakeholders, with the results being carefully weighed by regulators to arrive at their best estimate of the cost of equity. Developing the evidentiary record necessary to satisfy the *Hope* and *Bluefield* tests is a rigorous process that cannot be reduced to an isolated summary statistic from an industry publication such as RRA.

Q97. PLEASE ELABORATE ON WHY A RECENT AVERAGE ROE REPORTED BY RRA FALLS SHORT OF ACCEPTED REGULATORY STANDARDS.

A97. Setting a utility's ROE is a company-specific process and is a function of investors' perceptions of the risks and prospects for the subject company at a given point in time. Meanwhile, quarterly allowed ROEs reported by RRA are not necessarily representative or directly comparable to the utility at hand. That is, there may be an "apples and oranges" issue when the RRA data is applied in the current rate setting environment.

For instance, there can be significant differences in investment risks (*e.g.*, credit ratings) between the utilities that are the subject of a specific quarterly average ROE reported by RRA and the subject company in a rate proceeding, functional differences (integrated utilities versus "wires only" distribution services), as well as other utility-specific characteristics (*e.g.* size differences, capital requirements, and economic conditions in the service territory). Finally, capital market conditions during the evidentiary record that support the decisions reported by RRA are not likely to be identical to those prevailing during a subsequent rate proceeding. The very nature of RRA's quarterly publication schedule ensures that there will always be a lag between the results it reports and the ongoing case under study. All of these differences can lead to a potential disconnect between the broad summary statistics reported by RRA and the comprehensive and detailed analyses required to meet the *Hope* and *Bluefield* standards.

Q98. DON'T THESE SAME CONCERNS EQUALLY AFFECT YOUR USE OF THE RRA-REPORTED AUTHORIZED ROES TO CALCULATE YOUR RISK PREMIUM COST OF EQUITY ESTIMATE?

A98. No. My risk premium study considers all reported data concerning allowed ROEs over a 44-year horizon. As a result, it incorporates findings that reflect regulators' broad assessment of the required rate of return for the electric utility industry in general and is not unduly influenced by the specific risks or circumstances of a small subset of the industry that make up an isolated statistic based on decision in a particular calendar quarter. In addition, my application of the risk premium approach based on allowed ROEs from RRA specifically accounts for the impact of changes in capital market conditions by adjusting for the observed inverse relationship between equity risk premiums and interest rates, and by incorporating current bond yields when calculating the implied cost of equity.

Q99. COULD THE PROCESS BECOME CIRCULAR IF STATE REGULATORS WERE TO ROUTINELY ACCEPT ROE RESULTS FROM OTHER STATES AS THE BASIS TO SET A UTILITY'S RETURN?

A99. Yes. As noted above, the standard practice in regulatory proceedings is to consider the results of numerous approaches that are grounded in current capital market evidence when establishing a utility's ROE. If, instead, regulators were to simply rely on the most recent determinations of other state agencies, the connection between regulatory findings and investors in the capital markets would soon be broken.[68] For this reason, state regulatory agencies are charged with the responsibility of independently evaluating detailed evidence to establish an ROE corresponding to the

[68] While RRA data may be one factor considered by investors in developing their expectations, the required return is a function of the underlying risks associated with the utility at issue and the other investment opportunities available in the capital markets, including non-utility firms.

specific risks, capital market conditions, and investor expectations facing the utility under its jurisdiction. This is precisely the standard dictated by the *Hope* and *Bluefield* decisions.

Q100. ARE YOU SAYING THERE IS NO PLACE FOR RRA DATA IN THIS PROCESS?

A100. No. As discussed earlier, I use such data in my risk premium approach as an input to calculate annual average historical risk premiums, which are then adjusted to account for current capital market conditions and specific risk differences. Using this method, allowed ROE data from RRA is one of a number of inputs in a comprehensive, multi-year study that ultimately leads to a cost of equity estimate specific to the utility at hand and steeped in both investor expectations and financial theory.

It is also common to reference allowed ROEs reported by RRA as a benchmark or guidepost when assessing the reasonableness of cost of equity estimates derived from primary methodologies, such as the DCF and CAPM. In other words, RRA data is valuable as a "secondary" approach, useful in judging whether an ROE estimate based on the application of accepted financial models makes sense "on its face." In the right context, allowed ROE data from RRA can contribute in a valuable supporting role as part of the ROE estimation process.

H. Expected Earnings Approach

Q101. WHAT OTHER ANALYSES DO YOU CONDUCT TO ESTIMATE THE COST OF COMMON EQUITY?

A101. As I noted earlier, I also evaluate the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q102. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A102. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. Such an outcome would violate the *Hope* and *Bluefield* standards and undermine the utility's access to capital on reasonable terms.

Q103. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?

A103. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices – both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is directly analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q104. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR LGE/KU BASED ON THE EXPECTED EARNINGS APPROACH?

A104. For the firms in the Utility Group, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit No. 9. As I explained earlier in my discussion of the br+sv growth rates used in applying the DCF model, Value Line's returns on common equity are calculated using year-end equity balances, which understates the average return earned over the year.[69] Accordingly, these year-end values were converted to average returns using the same adjustment factor

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[69] For example, to compute the annual return on a passbook savings account with a beginning balance of $1,000 and an ending balance of $5,000, the interest income would be divided by the average balance of $3,000. Using the $5,000 balance at the end of the year would understate the actual return.

discussed earlier and developed on Exhibit No. 6. As shown on Exhibit No. AMM-9, Value Line's projections for the Utility Group suggest an average ROE of approximately 10.4%, with a midpoint value of 10.9%.

I. Flotation Costs

Q105. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE RETURN ON EQUITY FOR A UTILITY?

A105. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity. While LGE/KU have no publicly traded stock and do not incur flotation costs directly, equity capital is provided by investors through PPL's sale of common shares. Thus, these expenses are also relevant when evaluating the fair and reasonable ROE for a wholly-owned subsidiary, such as the Companies.

Q106. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?

A106. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q107. THE KPSC HAS NOT ROUTINELY APPROVED A FLOTATION COST ADJUSTMENT FOR LGE/KU. WHY DO YOU CONTINUE TO RECOMMEND AN ADJUSTMENT IN THIS CASE?

A107. I am aware that the KPSC has not routinely approved a flotation cost adjustment for LGE/KU in past proceedings. Nevertheless, the financial literature and evidence in this case provides a sound theoretical and practical basis to include consideration of flotation costs for the Companies. An adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues has been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[70] Similarly, *New Regulatory Finance* contains the following discussion:

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[70] E. F. Brigham, D. A. Aberwald, and L. C. Gapenski, *Common Equity Flotation Costs and Rate Making*, Pub. Util. Fortnightly, May, 2, 1985.

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[71]

Q108. CAN YOU ILLUSTRATE WHY INVESTORS WILL NOT HAVE THE OPPORTUNITY TO EARN THEIR REQUIRED ROE UNLESS A FLOTATION COST ADJUSTMENT IS INCLUDED?

A108. Yes. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 10.5%, the expected dividend in year 1 is $0.50 (i.e., a dividend yield of 5%), and that growth is expected to be 5.5% annually. As developed in Table 5 below, if the allowed rate of return on common equity is only equal to the utility's 10.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 5.25%, instead of 5.5%:

TABLE 5
NO FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	10.50%	$ 1.00	$ 0.50	50.0%
2	$ 9.52	$ 0.50	$ 10.02	$10.52	1.050	10.50%	$ 1.05	$ 0.53	50.0%
3	$ 9.52	$ 0.53	$ 10.55	$11.08	1.050	10.50%	$ 1.11	$ 0.55	50.0%
Growth			**5.25%**	**5.25%**			**5.25%**	**5.25%**	

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[71] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 335.

The reason that investors never really earn 10.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Including a flotation cost adjustment allows investors to be fully compensated for the impact of these costs. One commonly referenced method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown in Table 6 below, by allowing a rate of return on common equity of 10.75% (an 10.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 10.5% required rate of return, since actual growth is now equal to 5.5%:

TABLE 6
INCLUDING FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	10.75%	$ 1.02	$ 0.50	48.9%
2	$ 9.52	$ 0.52	$ 10.04	$10.55	1.050	10.75%	$ 1.08	$ 0.53	48.9%
3	$ 9.52	$ 0.55	$ 10.60	$11.13	1.050	10.75%	$ 1.14	$ 0.56	48.9%
Growth			**5.50%**	**5.50%**			**5.50%**	**5.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q109. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A109. The most common method used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. In Exhibit No. 10, I have gathered data on the most recent open-market common stock issues for each company in Value Line's electric and gas utility industry groups. For all companies in the utility industry, flotation costs averaged 2.85%. Applying this 2.85% expense percentage to the Utility Group dividend yield of 4.00% produces a flotation cost adjustment on the order of 10 basis points. I thus recommend the KPSC increase the cost of equity by 10 basis points in arriving at a fair and reasonable ROE for LGE/KU.

Q110. HAVE OTHER REGULATORS RECOGNIZED FLOTATION COSTS IN EVALUATING A FAIR AND REASONABLE ROE?

A110. Yes. For example, in Docket No. UE-991606 the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity:

> The Commission also agrees with both Dr. Avera and Dr. Lurito that a 25 basis point markup for flotation costs should be made. This amount compensates the Company for costs incurred from past issues of common stock. Flotation costs incurred in connection with a sale of common stock are not included in a utility's rate base because the portion of gross proceeds that is used to pay these costs is not available to invest in plant and equipment.[72]

In Case No. INT-G-16-02 the staff of the Idaho Public Utilities Commission supported the use of the same flotation cost methodology that I recommend above, concluding:

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[72] *Third Supplemental Order*, WUTC Docket No. UE-991606, *et al.* (September 2000) at 95.

> [I]s the standard equation for flotation cost adjustments and is referred to as the "conventional" approach. Its use in regulatory proceedings is widespread, and the formula is outlined in several corporate finance textbooks.[73]

More recently, the Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, recommended a 10 basis point flotation cost adjustment for a gas utility.[74] Similarly, the South Dakota Public Utilities Commission has recognized the impact of issuance costs, concluding that, "recovery of reasonable flotation costs is appropriate."[75] Another example of a regulator that approves common stock issuance costs is the Mississippi Public Service Commission, which routinely includes a flotation cost adjustment in its Rate Stabilization Adjustment Rider formula.[76] The Public Utilities Regulatory Authority of Connecticut[77] the Minnesota Public Utilities Commission[78] and the Virginia State Corporation Commission[79] have also recognized that flotation costs are a legitimate consideration in setting a fair and reasonable ROE.

VI. NON-UTILITY BENCHMARK

Q111. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A111. This section presents the results of my DCF analysis applied to a group of low-risk firms in the competitive sector, which I refer to as the "Non-Utility Group." This analysis was not directly considered in arriving at my recommended ROE range of

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[73] Case No. INT-G-16-02, *Direct Testimony of Mark Rogers* (Dec. 16, 2016) at 18.

[74] Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53.

[75] *Northern States Power Co*, EL11-019, Final Decision and Order at P 22 (2012).

[76] *See*, *e.g.*, Entergy Mississippi Formula Rate Plan FRP-7, https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwiLs4Sy67nsAhVKHqwKHddgA1wQFjABegQIBRAC&url=https%3A%2F%2Fcdn.entergy-mississippi.com%2Fuserfiles%2Fcontent%2Fprice%2Ftariffs%2Feml_frp.pdf&usg=AOvVaw1vyc6J_1IccZshzpfCtD0v (last visited Oct. 16, 2020).

[77] *See, e.g.*, Docket No. 14-05-06, Decision (Dec. 17, 2014) at 133-134.

[78] *See, e.g.,* Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order at 9 (2011).

[79] Roanoke Gas Company, Case No. PUR-2018-00013, *Final Order*, (Jan. 24, 2020) at 6.

reasonableness; however, it is my opinion that this is relevant consideration in evaluating a fair ROE for the Companies.

Q112. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A112. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q113. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?

A113. Yes. The cost of equity capital in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[80] As in *Bluefield*, there is nothing to restrict "other enterprises" to the utility industry.

Q114. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP HELP TO IMPROVE THE RELIABILITY OF DCF RESULTS?

A114. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. Because the Non-Utility Group includes low-risk companies from more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

Q115. HOW DID YOU DEVELOP THE NON-UTILITY GROUP?

A115. My low-risk group of competitive firms was composed of those U.S. companies followed by Value Line that:

(1) pay common dividends;
(2) have a Safety Rank of "1";
(3) have a Financial Strength Rating of "A" or greater;
(4) have a beta of 1.00 or less; and
(5) have investment grade credit ratings from S&P and Moody's.[81]

Q116. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE UTILITY GROUP?

A116. Table 7 compares the Non-Utility Group with the Utility Group and LGE/KU across the four key risk measures discussed earlier:

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[80] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

[81] Credit rating firms, such as S&P, use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'AAA', 'AA', 'A', and 'BBB' ratings are considered investment grade. Credit ratings for bonds below these designations ('BB', 'B', 'CCC', etc.) are considered speculative grade, and are commonly referred to as "junk bonds". The term "investment grade" refers to bonds with ratings in the 'BBB' category and above.

TABLE 7
COMPARISON OF RISK INDICATORS

	Credit Rating		Value Line		
	S&P	Moody's	Safety Rank	Financial Strength	Beta
Non-Utility Group	A	A2	1	A+	0.83
Utility Group	BBB+	Baa2	2	A	0.87
LGE/KU	A-	A3	2	B++	1.10

When considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the Utility Group and LGE/KU are greater than those of the firms in the Non-Utility Group.

The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Procter & Gamble, and Walmart, have long corporate histories, well-established track records, and exceedingly conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group of approximately 2.4%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q117. DO THE BETA VALUES FOR THE NON-UTILITY GROUP ADDRESS THE CONCERNS EXPRESSED BY THE KPSC IN A PRIOR RATE PROCEEDING?

A117. Yes. The KPSC concluded in Case No. 2009-00548 that utilities must compete with non-regulated firms for capital and recognized that investors consider the opportunity costs associated with investment alternatives outside the utility industry. However, the KPSC found that lower beta values for utility common stocks supported a finding that the non-utility companies were "riskier alternatives."[82] My proxy group criteria restricted the Non-Utility Group to include only firms with beta values of 1.00 or less, with the group's average beta of 0.83 being somewhat lower than the 0.87 value corresponding to the Utility Group.

Q118. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A118. I applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Utility Group, with the results being presented in Exhibit No. 11. As summarized in Table 8, below, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 8
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	Average	Midpoint
Value Line	10.3%	10.2%
IBES	9.6%	9.9%
Zacks	9.7%	9.8%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for LGE/KU.

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[82] Case No. 2009-00548, Order at 31 (July 30, 2010).

VII. CAPITAL STRUCTURE

Q119. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A119. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of any remaining cash flow.

Q120. WHAT COMMON EQUITY RATIOS ARE USED IN LGE'S AND KU'S CAPITAL STRUCTURES?

A120. The Companies' capital structures are discussed in the testimony of Daniel K. Arbough. As summarized there, common equity as a percent of the capital sources used to compute the overall rate of return for LGE/KU is approximately 53%.

Q121. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE UTILITY GROUP?

A121. As shown on page 1 of Exhibit No. 12, common equity ratios for the individual firms in the Utility Group ranged from a low of 27.8% to a high of 67.7% at year-end 2019 and averaged 46.1%.[83] Excluding the highest and lowest results would result in an adjusted equity ratio of 45.9%. Meanwhile, Value Line's three-to-five year forecast

[83] Adjusting these averages to reflect the same proportion of short-term debt included in LGE and KU's capitalization would produce adjusted equity ratios of 45.9% and 45.7%, respectively.

indicates an average common equity ratio of 46.9% for the Utility Group, with the individual equity ratios ranging from 32.0% to 59.0%.[84]

Q122. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY COMPARABLE UTILITY OPERATING COMPANIES?

A122. Pages 2 and 3 of Exhibit No. 12 displays capital structure data at year-end 2019 for the group of electric utility operating companies owned by the firms in the Utility Group used to estimate the cost of equity.[85] As shown there, common equity ratios for these utilities averaged 53.1%,[86] with 22 of the 49 operating companies having equity ratios equal to or greater than the common equity ratio of approximately 53% requested by LGE and KU.

Q123. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR ASSESSMENT OF A COMPANY'S CAPITAL STRUCTURE?

A123. Utilities are facing significant capital investment plans, the need to accommodate the impact of the Tax Cuts and Jobs Act, and ongoing regulatory risks. Coupled with the potential for turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with the need to maintain the continuous access to capital that is required to fund operations and necessary system investment.

In addition, depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating the Companies' financial risk. Because investors consider the

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[84] Adjusting these averages to reflect the same proportion of short-term debt included in LGE and KU's capitalization would produce adjusted equity ratios of 46.8% and 46.7%, respectively.

[85] I excluded LGE and KU from this analysis.

[86] Adjusting this average capitalization for the electric operating companies to include short-term debt in the same proportion as LGE and KU would result in an adjusted equity ratios of 52.8% and 52.7%, respectively.

debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. Unless the utility takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken its creditworthiness and imply greater risk.

Q124. DO ONGOING ECONOMIC AND CAPITAL MARKET UNCERTAINTIES ALSO INFLUENCE THE APPROPRIATE CAPITAL STRUCTURE FOR LGE/KU?

A124. Yes. Financial flexibility plays a crucial role in ensuring the wherewithal to meet funding needs, and utilities with higher financial leverage may be foreclosed or have limited access to additional borrowing, especially during times of stress. As Moody's observed:

> Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to capital markets to assure adequate sources of funding and to maintain financial flexibility. During times of distress and when capital markets are exceedingly volatile and tight, liquidity becomes critically important because access to capital markets may be difficult.[87]

Confirming this view, S&P noted that "availability to the equity market remains extraordinarily challenging" for utilities, and concluded that "lack of access to the equity market" will also pose a risk to financial standing in the industry.[88] As a result, the Companies' capital structure must maintain adequate equity to preserve the flexibility necessary to maintain continuous access to capital even during times of unfavorable market conditions.

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[87] Moody's Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).

[88] S&P Global Ratings, *COVID-19: The Outlook For North American Regulated Utilities Turns Negative* (Apr. 2, 2020).

Q125. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF LGE/KU'S REQUESTED CAPITAL STRUCTURE?

A125. Based on my evaluation, I concluded that the common equity ratio of approximately 53% requested by LGE/KU represents a reasonable mix of capital sources from which to calculate the Companies' overall rate of return. Although this common equity ratio is higher than the historical and projected averages maintained by the Utility Group, it is well within the range of individual results and consistent with the capitalization maintained by other utility operating companies. While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. The Companies' capital structures reflect the need to support the credit standing and financial flexibility of LGE and KU as they seek to fund system investments and meet the needs of customers.

Q126. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A126. Yes, it does.

STATE OF TEXAS)
)
COUNTY OF TRAVIS)

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and states that he is a President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17th day of NOVEMBER 2020.

BRUCE H FAIRCHILD
Notary ID #131906507
My Commission Expires
February 25, 2023

NOTARY PUBLIC STATE OF TEXAS

(SEAL)
Notary Public

Notary Public, ID No. 131906507

My Commission Expires:

2/25/2023

EXHIBIT NO. 1

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrien M. McKenzie. My business address is 3907 Red River St., Austin, Texas 78751.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a principal in FINCAP, Inc., a firm engaged primarily in financial, economic, and policy consulting in the field of public utility regulation.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony in over 140 proceedings filed with the Federal Energy Regulatory Commission ("FERC") and regulatory agencies in Alaska, Arkansas, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair rate of return on equity for regulated electric, gas, and water utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

FINCAP was formed in 1979 as an economic and financial consulting firm serving clients in both the regulated and competitive sectors. FINCAP conducts assignments ranging from broad qualitative analyses and policy consulting to technical analyses and research. The firm's experience is in the areas of public utilities, valuation of closely-held businesses, and economic evaluations (e.g., damage and cost/benefit analyses). Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I am a member of the CFA Institute, the CFA Society of Austin. A resume containing the details of my qualifications and experience is attached below.

ADRIEN M. McKENZIE

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River Street
Austin, Texas 78751
(512) 923-2790
FAX (512) 458–4768
amm.fincap@outlook.com

Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA®) designation. He has over 30 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

President FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA®) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014).

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012).

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and sponsored prefiled testimony submitted in over 140 regulatory proceedings. In addition to filings before regulatory agencies in Alaska, Arkansas, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of rate of return on equity ("ROE"), and has broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included developing cost of service and cost allocation studies, the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

ROE ANALYSES

SUMMARY OF RESULTS

Method	Average		Midpoint
DCF			
Value Line	8.8%		10.2%
IBES	9.2%		9.3%
Zacks	9.1%		9.7%
Internal br + sv	8.3%		8.9%
CAPM	10.7%		10.7%
Empirical CAPM	11.0%		11.0%
Utility Risk Premium			
Current Bond Yields		9.3%	
Projected Bond Yield		10.2%	
Expected Earnings	10.4%		10.9%

ROE Recommendation			
Proxy Group			
Recommended Cost of Equity Range	9.3%	--	10.5%
Flotation Cost Adjustment			
Dividend Yield		3.7%	
Flotation Cost Percentage		2.9%	
Adjustment		0.1%	
Recommended ROE Range	**9.4%**	--	**10.6%**
Recommended ROE		**10.0%**	

UTILITY GROUP

	Type of Adjustment Clause						New Capital				
Holding Company	**Elec. Fuel/ Purch. Pwr**	**Conserv. Program Expense**	**Decoupling Full**	**Decoupling Partial**	**Renew-ables Expense**	**Environ-mental Compliance**	**Gener-ation Capacity**	**Generic Infra-structure**	**Trans-mission Expense**	**Other***	**Future Test Year**
1 Algonquin Pwr & Util	D	✓	--	✓	--	✓	--	✓	✓	✓	P
2 ALLETE	✓	✓	--	--	✓	✓	--	--	✓	✓	C
3 Alliant Energy	✓	✓	--	--	✓	✓	--	--	✓	✓	C
4 Ameren Corp.	D	✓	--	✓	✓	✓	--	✓	✓	✓	O,P
5 Avangrid, Inc.	D	✓	✓	--	✓	--	--	--	✓	✓	C
6 Avista Corp.	✓	✓	✓	✓	✓	--	--	--	--	--	P
7 Black Hills Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	O
8 CMS Energy Corp.	✓	✓	--	--	✓	--	--	--	✓	--	C
9 Consolidated Edison	D	✓	✓	--	✓	--	--	✓	--	✓	C,P
10 DTE Energy Co.	✓	✓	--	--	✓	--	--	--	✓	--	C
11 Duke Energy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	C,O,P
12 Entergy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	O,P
13 Eversource Energy	D	✓	✓	✓	✓	✓	--	✓	✓	✓	C
14 NorthWestern Corp.	✓	✓	--	--	✓	--	--	--	--	✓	--
15 Pub Sv Enterprise Grp.	D	✓	--	--	✓	--	--	✓	--	✓	P
16 Sempra Energy	D	✓	✓	--	--	--	--	✓	✓	✓	C
17 Southern Company	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	C,O
18 WEC Energy Group	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	C
19 Xcel Energy Inc.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	C,O

Sources:
Exhibit No. 3, pages 2-5, contain operating company data that are aggregated into the parent company data on this page.

Notes:
D - Delivery-only utility.
C - Fully-forecasted test years commonly used in the state listed for this operating company.
O - Fully-forecasted test years occasionally used in the state listed for this operating company.
P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.
* Recover mechanisms for other expenses, such as taxes, franchise fees, bad debts, storm costs, pensions, societal benefits, vegetation management, and decommissioning.

UTILITY GROUP OPERATING COS.

	HOLDING COMPANY/ Operating Company		Type of Adjustment Clause (a)										**Future Test Year (b)**
			Elec. Fuel/ Purch. Pwr	**Conserv. Program Expense**	**Decoupling**		**Renew-ables Expense**	**Environ-mental Compliance**	**New Capital**		**Trans-mission Expense**	**Other***	
					Full	**Partial**			**Gener-ation Capacity**	**Generic Infra-structure**			
1	**ALGONQUIN PWR. & UTIL.**												
	Empire District Electric	KS	✓	✓	--	--	--	✓	--	--	✓	✓	--
	Empire District Electric	MO	✓	--	--	--	--	✓	--	--	✓	✓	P
	Liberty Util. (Granite State Electric)	NH	D	--	--	✓	--	--	--	✓	--	--	--
2	**ALLETE**												
	Minnesota Power	MN	✓	✓	--	--	✓	✓	--	--	✓	✓	C
3	**ALLIANT ENERGY CORP.**												
	Interstate Power & Light	IA	✓	✓	--	--	✓	✓	--	--	✓	✓	--
	Wisconsin Power & Light	WI	✓	--	--	--	--	--	--	--	--	✓	C
4	**AMEREN CORP.**												
	Ameren Illinois	IL	D	✓	--	--	✓	✓	--	--	✓	✓	O
	Union Electric	MO	✓	✓	--	✓	✓	✓	--	✓	✓	✓	P
5	**AVANGRID**												
	United Illuminating	CT	D	✓	✓	--	--	--	--	--	✓	--	C
	Central Maine Power	ME	D	--	✓	--	--	--	--	--	--	✓	C
	New York State Electric & Gas	NY	D	--	✓	--	✓	--	--	--	--	✓	C
	Rochester Gas & Electric	NY	D	--	✓	--	✓	--	--	--	--	✓	C
6	**AVISTA CORP.**												
	Alaska Electric Light & Power	AK	✓	--	--	--	--	--	--	--	--	--	--
	Avista Corp.	ID	✓	✓	✓	--	--	--	--	--	--	--	P
	Avista Corp.	WA	✓	✓	--	✓	✓	--	--	--	--	--	--
7	**BLACK HILLS CORP.**												
	Black Hills Colorado Electric	CO	✓	✓	--	--	✓	--	✓	✓	--	✓	--
	Black Hills Power	SD	✓	✓	--	✓	✓	✓	--	--	✓	✓	--
	Cheyenne Light Fuel & Power	WY	✓	✓	--	✓	✓	--	--	--	--	✓	O
8	**CMS ENERGY**												
	Consumers Energy	MI	✓	✓	--	--	✓	--	--	--	✓	--	C
9	**CONSOLIDATED EDISON**												
	Rockland Electric	NJ	D	✓	--	--	✓	--	--	✓	--	✓	P
	Consolidated Edison of New York	NY	D	--	✓	--	✓	--	--	--	--	✓	C
	Orange & Rockland Utilities	NY	D	--	✓	--	✓	--	--	--	--	--	C
10	**DTE ENERGY CO.**												
	DTE Electric	MI	✓	✓	--	--	✓	--	--	--	✓	--	C

UTILITY GROUP OPERATING COS.

			Type of Adjustment Clause (a)										
									New Capital				
	HOLDING COMPANY/ Operating Company		**Elec. Fuel/ Purch. Pwr**	**Conserv. Program Expense**	**Decoupling Full**	**Decoupling Partial**	**Renew-ables Expense**	**Environ-mental Compliance**	**Gener-ation Capacity**	**Generic Infra-structure**	**Trans-mission Expense**	**Other***	**Future Test Year (b)**
11	**DUKE ENERGY**												
	Duke Energy Florida	FL	✓	✓	--	--	--	✓	✓	--	--	✓	C
	Duke Energy Indiana	IN	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	--
	Duke Energy Kentucky	KY	✓	✓	--	✓	✓	✓	--	--	--	✓	O
	Duke Energy Carolinas	NC	✓	✓	--	--	✓	✓	--	--	--	--	--
	Duke Energy Progress	NC	✓	✓	--	--	✓	✓	--	--	--	--	--
	Duke Energy Ohio	OH	D	✓	--	✓	✓	--	--	✓	✓	✓	P
	Duke Energy Progress	SC	✓	✓	--	--	--	✓	--	--	--	--	--
	Duke Energy Carolinas	SC	✓	✓	--	--	--	✓	--	--	--	--	--
12	**ENTERGY CORP.**												
	Entergy Arkansas	AR	✓	✓	--	✓	✓	--	✓	✓	✓	✓	P
	Entergy New Orleans	LA	✓	✓	--	✓	--	✓	✓	--	✓	✓	O
	Entergy Louisiana	LA	✓	✓	--	✓	--	✓	✓	✓	✓	✓	O
	Entergy Mississippi	MS	✓	✓	--	✓	--	✓	--	--	✓	✓	O
	Entergy Texas	TX	✓	✓	--	--	--	--	--	✓	--	✓	--
13	**EVERSOURCE ENERGY**												
	Connecticut Light and Power	CT	D	✓	✓	--	--	--	--	✓	✓	--	C
	NSTAR Electric	MA	D	✓	✓	--	✓	--	--	✓	✓	✓	--
	Public Service Co. of New Hampshire	NH	✓	--	--	✓	--	--	--	✓	✓	--	--
14	**NORTHWESTERN CORP.**												
	NorthWestern Corp.	MT	✓	✓	--	--	✓	--	--	--	--	✓	--
	NorthWestern Corp.	SD	✓	✓	--	--	--	--	--	--	--	--	--
15	**PUB SV ENTERPRISE GRP**												
	Public Service Electric & Gas	NJ	D	✓	--	--	✓	--	--	✓	--	✓	P
16	**SEMPRA ENERGY**												
	San Diego Gas & Electric	CA	✓	--	✓	--	--	--	--	--	--	✓	C
	Oncor Electric Delivery	TX	D	✓	--	--	--	--	--	✓	✓	--	--
17	**SOUTHERN CO.**												
	Alabama Power	AL	✓	--	--	--	✓	✓	✓	--	--	✓	C
	Georgia Power	GA	✓	--	--	--	--	--	✓	--	--	--	C
	Mississippi Power	MS	✓	✓	--	✓	--	✓	--	--	--	✓	O

UTILITY GROUP OPERATING COS.

		Type of Adjustment Clause (a)											
								New Capital					
HOLDING COMPANY/ Operating Company		**Elec. Fuel/ Purch. Pwr**	**Conserv. Program Expense**	**Decoupling Full**	**Decoupling Partial**	**Renew-ables Expense**	**Environ-mental Compliance**	**Gener-ation Capacity**	**Generic Infra-structure**	**Trans-mission Expense**	**Other***	**Future Test Year (b)**
18 WEC ENERGY GROUP												
Wisconsin Electric Power	MI	✓	✓	--	--	✓	--	--	--	--	--	C
Wisconsin Electric Power	WI	✓	--	--	--	✓	--	--	--	--	✓	C
Wisconsin Public Service	WI	✓	--	--	--	--	--	--	--	--	✓	C
19 XCEL ENERGY, INC.												
Public Service Co. of Colorado	CO	✓	✓	--	--	✓	✓	✓	✓	--	✓	--
Northern States Power-Minnesota	MN	✓	✓	--	✓	✓	✓	--	--	✓	--	C
Southwestern Public Service	NM	✓	✓	--	--	✓	--	--	--	--	✓	O
Northern States Power-Minnesota	ND	✓	--	--	--	--	--	--	✓	--	✓	O
Northern States Power-Minnesota	SD	✓	✓	--	✓	--	✓	✓	✓	--	✓	--
Southwestern Public Service	TX	✓	✓	--	--	--	--	--	✓	✓	✓	--
Northern States Power-Wisconsin	WI	✓	--	--	--	--	--	--	--	--	✓	C

Sources:
(a) S&P Global, Market Intelligence, RRA Regulatory Focus, *"Adjustment Clauses-A State-by-State Overview,"* Nov. 12, 2019.
(b) Edison Electric Institute, *"Alternative Regulation for Emerging Utility Challenges: 2015 Update,"* Nov. 11, 2015.

Notes:
D - Delivery-only utility.
C - Fully-forecasted test years commonly used in the state listed for this operating company.
O - Fully-forecasted test years occasionally used in the state listed for this operating company.
P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.
* Recover mechanisms for other expenses, such as taxes, franchise fees, bad debts, storm costs, pensions, societal benefits, vegetation management, and decommissioning.

DCF MODEL - UTILITY GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Algonquin Pwr & Util	$ 14.32	$ 0.62	4.3%
2	ALLETE	$ 52.68	$ 2.55	4.8%
3	Alliant Energy	$ 52.59	$ 1.52	2.9%
4	Ameren Corp.	$ 78.57	$ 2.08	2.6%
5	Avangrid, Inc.	$ 50.03	$ 1.76	3.5%
6	Avista Corp.	$ 35.06	$ 1.64	4.7%
7	Black Hills Corp.	$ 54.91	$ 2.23	4.1%
8	CMS Energy Corp.	$ 61.37	$ 1.71	2.8%
9	Consolidated Edison	$ 75.36	$ 3.11	4.1%
10	DTE Energy Co.	$ 116.50	$ 4.34	3.7%
11	Duke Energy Corp.	$ 84.63	$ 3.88	4.6%
12	Entergy Corp.	$ 98.92	$ 3.80	3.8%
13	Eversource Energy	$ 84.54	$ 2.34	2.8%
14	NorthWestern Corp.	$ 50.37	$ 2.45	4.9%
15	Pub Sv Enterprise Grp.	$ 53.57	$ 2.00	3.7%
16	Sempra Energy	$ 120.16	$ 4.34	3.6%
17	Southern Company	$ 53.91	$ 2.60	4.8%
18	WEC Energy Group	$ 96.52	$ 2.66	2.8%
19	Xcel Energy Inc.	$ 69.56	$ 1.77	2.5%
	Average			**3.7%**

(a) Average of closing prices for 30 trading days ended Oct. 9, 2020.
(b) The Value Line Investment Survey, Summary & Index (Oct. 9, 2020).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Algonquin Pwr & Util	n/a	5.7%	7.9%	n/a
2	ALLETE	4.5%	7.0%	n/a	3.2%
3	Alliant Energy	5.5%	5.3%	5.5%	4.7%
4	Ameren Corp.	6.0%	6.0%	6.9%	6.0%
5	Avangrid, Inc.	4.0%	4.6%	5.3%	1.4%
6	Avista Corp.	1.0%	5.8%	5.1%	3.0%
7	Black Hills Corp.	3.5%	4.7%	5.8%	3.8%
8	CMS Energy Corp.	7.5%	7.1%	7.0%	7.2%
9	Consolidated Edison	3.0%	2.6%	2.0%	3.3%
10	DTE Energy Co.	6.0%	6.0%	5.7%	5.3%
11	Duke Energy Corp.	5.0%	1.6%	3.1%	3.1%
12	Entergy Corp.	3.0%	5.4%	5.4%	4.9%
13	Eversource Energy	5.5%	6.4%	6.6%	4.7%
14	NorthWestern Corp.	1.5%	3.8%	3.4%	2.7%
15	Pub Sv Enterprise Grp.	5.0%	1.5%	3.5%	5.2%
16	Sempra Energy	10.0%	6.3%	7.4%	7.3%
17	Southern Company	3.0%	4.6%	4.0%	3.6%
18	WEC Energy Group	6.0%	6.0%	5.9%	4.2%
19	Xcel Energy Inc.	6.0%	5.9%	5.8%	5.0%

(a) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).
(b) www.finance.yahoo.com (retreived Oct. 3, 2020).
(c) www.zacks.com (retrieved Oct. 3, 2020).
(d) See Exhibit No. 5.

DCF MODEL - UTILITY GROUP

COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Algonquin Pwr & Util	n/a	10.0%	12.2%	n/a
2	ALLETE	9.3%	11.8%	n/a	8.0%
3	Alliant Energy	8.4%	8.2%	8.4%	7.6%
4	Ameren Corp.	8.6%	8.6%	9.5%	8.6%
5	Avangrid, Inc.	7.5%	8.1%	8.8%	4.9%
6	Avista Corp.	5.7%	10.5%	9.8%	7.7%
7	Black Hills Corp.	7.6%	8.8%	9.8%	7.9%
8	CMS Energy Corp.	10.3%	9.9%	9.8%	10.0%
9	Consolidated Edison	7.1%	6.7%	6.1%	7.5%
10	DTE Energy Co.	9.7%	9.7%	9.4%	9.0%
11	Duke Energy Corp.	9.6%	6.2%	7.7%	7.7%
12	Entergy Corp.	6.8%	9.2%	9.3%	8.7%
13	Eversource Energy	8.3%	9.2%	9.4%	7.5%
14	NorthWestern Corp.	6.4%	8.7%	8.3%	7.6%
15	Pub Sv Enterprise Grp.	8.7%	5.2%	7.2%	8.9%
16	Sempra Energy	13.6%	9.9%	11.0%	10.9%
17	Southern Company	7.8%	9.4%	8.8%	8.5%
18	WEC Energy Group	8.8%	8.7%	8.7%	6.9%
19	Xcel Energy Inc.	8.5%	8.4%	8.4%	7.6%
	Average (b)	**8.8%**	**9.2%**	**9.1%**	**8.3%**
	Midpoint (b) (c)	**10.2%**	**9.3%**	**9.7%**	**8.9%**

(a) Sum of dividend yield (Exhibit No. 4, p. 1) and respective growth rate (Exhibit No. 4, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

LOW-END THRESHOLD ADJUSTMENT

Atlantic Path 15 / Startrans / So. Cal Edison		*Pioneer Transmission*	
	Baa Yield		**Baa Yield**
Jun-07	6.54%	Apr-08	6.81%
Jul-07	6.49%	May-08	6.79%
Aug-07	6.51%	Jun-08	6.93%
Sep-07	6.45%	Jul-08	6.97%
Oct-07	6.36%	Aug-08	6.98%
Nov-07	6.27%	Sep-08	7.15%

	Current		**Projected**	
Historical Baa Bond Yield	6.69%	(a)	6.69%	(a)
Current Baa Bond Yield	3.37%	(b)	4.79%	(c)
Change in Bond Yield	-3.32%		-1.90%	
Risk Premium/Interest Rate Relationship	-0.42103	(d)	-0.42103	(d)
Adjustment to Low-end Threshold	1.40%		0.80%	
Current Baa Bond Yield	3.37%		4.79%	
Original Threshold	1.00%		1.00%	
Adjustment	1.40%		0.80%	
Adjusted Low-end Threshold	**5.77%**		**6.59%**	

Low-end Test -- FERC Opinion No. 569-A	
Current Baa Bond Yield	3.37%
CAPM Market Risk Premium (e)	10.17%
Risk Premium Factor (f)	20.00%
Adjustment to Low-end Threshold	2.03%
Adjusted Low-end Threshold	**5.40%**

(a) Average Baa utility bond yield for 6-mo. periods ending Nov. 2007 and Sep. 2008.
(b) Average Baa utility bond yield for 6-months ended Sep. 2020.
(c) Average Baa utility bond yield for 2021-25 based on data from IHS Markit, Long-Term Macro Forecast - Baseline (May 28, 2020); Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020), Moody's Investors Service at www.credittrends.com.
(d) Exhibit No. 8, page 4.
(e) Exhibit No. 6, page 1.
(f) *Assoc. of Bus. Advocating Tariff Equity* , Opinion No. 569-A, 171 FERC ¶ 61,154 (2020).

BR+SV GROWTH RATE

UTILITY GROUP

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2024					Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Algonquin Pwr & Util	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	ALLETE	$4.25	$2.90	$51.75	31.8%	8.2%	1.0233	8.4%	2.7%	0.0145	0.3323	0.48%	3.2%
3	Alliant Energy	$3.00	$2.00	$28.25	33.3%	10.6%	1.0150	10.8%	3.6%	0.0266	0.4053	1.08%	4.7%
4	Ameren Corp.	$4.50	$2.45	$44.50	45.6%	10.1%	1.0398	10.5%	4.8%	0.0303	0.3862	1.17%	6.0%
5	Avangrid, Inc.	$2.50	$1.80	$51.75	28.0%	4.8%	1.0048	4.9%	1.4%	(0.0000)	(0.2176)	0.00%	1.4%
6	Avista Corp.	$2.50	$1.90	$31.75	24.0%	7.9%	1.0182	8.0%	1.9%	0.0277	0.3952	1.10%	3.0%
7	Black Hills Corp.	$4.25	$2.75	$46.75	35.3%	9.1%	1.0232	9.3%	3.3%	0.0134	0.3968	0.53%	3.8%
8	CMS Energy Corp.	$3.50	$2.15	$25.50	38.6%	13.7%	1.0429	14.3%	5.5%	0.0283	0.6077	1.72%	7.2%
9	Consolidated Edison	$5.00	$3.50	$62.50	30.0%	8.0%	1.0233	8.2%	2.5%	0.0274	0.3243	0.89%	3.3%
10	DTE Energy Co.	$8.50	$5.20	$79.25	38.8%	10.7%	1.0326	11.1%	4.3%	0.0229	0.4339	0.99%	5.3%
11	Duke Energy Corp.	$6.00	$4.15	$71.00	30.8%	8.5%	1.0214	8.6%	2.7%	0.0185	0.2526	0.47%	3.1%
12	Entergy Corp.	$7.00	$4.55	$64.00	35.0%	10.9%	1.0267	11.2%	3.9%	0.0204	0.4776	0.97%	4.9%
13	Eversource Energy	$4.50	$2.85	$49.00	36.7%	9.2%	1.0341	9.5%	3.5%	0.0306	0.4061	1.24%	4.7%
14	NorthWestern Corp.	$3.75	$2.80	$45.75	25.3%	8.2%	1.0169	8.3%	2.1%	0.0162	0.3900	0.63%	2.7%
15	Pub Sv Enterprise Grp.	$4.25	$2.30	$38.50	45.9%	11.0%	1.0249	11.3%	5.2%	0.0006	0.3583	0.02%	5.2%
16	Sempra Energy	$9.50	$5.60	$88.75	41.1%	10.7%	1.0533	11.3%	4.6%	0.0578	0.4621	2.67%	7.3%
17	Southern Company	$3.75	$2.86	$30.50	23.7%	12.3%	1.0188	12.5%	3.0%	0.0135	0.4917	0.66%	3.6%
18	WEC Energy Group	$4.75	$3.20	$38.00	32.6%	12.5%	1.0170	12.7%	4.1%	0.0001	0.6000	0.01%	4.2%
19	Xcel Energy Inc.	$3.50	$2.15	$32.35	38.6%	10.8%	1.0292	11.1%	4.3%	0.0163	0.4608	0.75%	5.0%

BR+SV GROWTH RATE **Exhibit No. 5**

UTILITY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2019			2024			Chg	2024				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2019	2024	Growth
1	Algonquin Pwr & Util	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2	ALLETE	61.4%	$3,633	$2,231	59.0%	$4,775	$2,817	4.8%	$90.0	$65.0	$77.5	1.498	51.70	54.25	0.97%
3	Alliant Energy	48.5%	$10,226	$4,960	48.0%	$12,000	$5,760	3.0%	$55.0	$40.0	$47.5	1.681	245.02	265.00	1.58%
4	Ameren Corp.	47.1%	$17,116	$8,062	49.0%	$24,500	$12,005	8.3%	$85.0	$60.0	$72.5	1.629	246.20	270.00	1.86%
5	Avangrid, Inc.	69.4%	$21,953	$15,235	57.5%	$27,800	$15,985	1.0%	$50.0	$35.0	$42.5	0.821	309.01	309.00	0.00%
6	Avista Corp.	50.6%	$3,835	$1,940	49.0%	$4,750	$2,328	3.7%	$60.0	$45.0	$52.5	1.654	67.18	73.00	1.68%
7	Black Hills Corp.	42.9%	$5,502	$2,360	48.0%	$6,200	$2,976	4.7%	$90.0	$65.0	$77.5	1.658	61.48	64.00	0.81%
8	CMS Energy Corp.	29.4%	$17,082	$5,022	32.0%	$24,100	$7,712	9.0%	$75.0	$55.0	$65.0	2.549	283.86	300.00	1.11%
9	Consolidated Edison	49.3%	$36,549	$18,019	50.0%	$45,500	$22,750	4.8%	$100.0	$85.0	$92.5	1.480	333.00	365.00	1.85%
10	DTE Energy Co.	42.3%	$27,607	$11,678	41.5%	$39,000	$16,185	6.7%	$160.0	$120.0	$140.0	1.767	192.21	205.00	1.30%
11	Duke Energy Corp.	44.1%	$101,807	$44,897	45.0%	$123,600	$55,620	4.4%	$110.0	$80.0	$95.0	1.338	733.00	785.00	1.38%
12	Entergy Corp.	37.1%	$27,557	$10,224	39.5%	$33,800	$13,351	5.5%	$140.0	$105.0	$122.5	1.914	199.15	210.00	1.07%
13	Eversource Energy	46.6%	$27,097	$12,627	46.5%	$38,200	$17,763	7.1%	$90.0	$75.0	$82.5	1.684	329.88	361.00	1.82%
14	NorthWestern Corp.	47.5%	$4,290	$2,038	50.0%	$4,825	$2,413	3.4%	$85.0	$65.0	$75.0	1.639	50.45	53.00	0.99%
15	Pub Sv Enterprise Grp.	52.3%	$28,832	$15,079	50.0%	$38,700	$19,350	5.1%	$65.0	$55.0	$60.0	1.558	504.00	505.00	0.04%
16	Sempra Energy	43.4%	$40,734	$17,679	51.5%	$58,500	$30,128	11.3%	$190.0	$140.0	$165.0	1.859	291.71	340.00	3.11%
17	Southern Company	39.5%	$69,594	$27,490	39.5%	$84,000	$33,180	3.8%	$70.0	$50.0	$60.0	1.967	1053.30	1090.00	0.69%
18	WEC Energy Group	47.4%	$21,355	$10,122	48.0%	$25,000	$12,000	3.5%	$105.0	$85.0	$95.0	2.500	315.43	315.50	0.00%
19	Xcel Energy Inc.	43.2%	$30,646	$13,239	42.5%	$41,700	$17,723	6.0%	$65.0	$55.0	$60.0	1.855	524.54	548.00	0.88%

(a) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2024 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change in common equity.
(h) Average of High and Low expected market prices divided by 2024 BVPS.

CAPM

Exhibit No. 6
Page 1 of 1

UTILITY GROUP

		(a)	(b)		(c)		(d)		(d)	(e)	
		Market Return (R_m)									
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**		**Unadjusted**	**Market**	**Size**	**CAPM**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Beta**	**K_e**	**Cap**	**Adjustment**	**Result**
1	Algonquin Pwr & Util	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$8,126	0.73%	11.3%
2	ALLETE	2.3%	9.2%	11.6%	1.4%	10.2%	0.85	10.0%	$2,800	1.10%	11.1%
3	Alliant Energy	2.3%	9.2%	11.6%	1.4%	10.2%	0.85	10.0%	$13,500	0.50%	10.5%
4	Ameren Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$20,000	0.50%	10.0%
5	Avangrid, Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$15,000	0.50%	10.0%
6	Avista Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$2,400	1.34%	11.9%
7	Black Hills Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.95	11.1%	$3,800	1.10%	12.2%
8	CMS Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$17,000	0.50%	10.0%
9	Consolidated Edison	2.3%	9.2%	11.6%	1.4%	10.2%	0.75	9.0%	$25,000	0.50%	9.5%
10	DTE Energy Co.	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$23,000	0.50%	11.1%
11	Duke Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.85	10.0%	$62,000	-0.28%	9.8%
12	Entergy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.95	11.1%	$20,000	0.50%	11.6%
13	Eversource Energy	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$30,000	0.50%	11.1%
14	NorthWestern Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$2,700	1.10%	11.7%
15	Pub Sv Enterprise Grp.	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$28,000	0.50%	11.1%
16	Sempra Energy	2.3%	9.2%	11.6%	1.4%	10.2%	0.95	11.1%	$35,000	-0.28%	10.8%
17	Southern Company	2.3%	9.2%	11.6%	1.4%	10.2%	0.90	10.6%	$57,000	-0.28%	10.3%
18	WEC Energy Group	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$30,000	0.50%	10.0%
19	Xcel Energy Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	0.80	9.5%	$34,000	-0.28%	9.3%
	Average (f)										**10.7%**
	Midpoint (f) (g)										**10.7%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Oct. 1, 2020).
(b) Average of weighted average earnings growth rates from IBES, Value Line, and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Oct. 2, 2020), www.valueline.com (retrieved Oct. 1, 2020), and www.zacks.com (retrieved Oct. 1, 2020).
(c) Average yield on 30-year Treasury bonds for the six-months ending Sep. 2020 based on data from http://www.fred.stlouisfed.org.
(d) The Value Line Investment Survey, Summary & Index (Oct. 9, 2020).
(e) Duff & Phelps, 2020 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(f) Excludes highlighted figures.
(g) Average of low and high values.

EMPIRICAL CAPM

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(e)	(f)	
		Market Return (R_m)					**Unadjusted RP**		**Beta Adjusted RP**							
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Weight**	***RP* [1]**	**Beta**	**Weight**	***RP* [2]**	**Total RP**	**Unadjusted K_e**	**Market Cap**	**Size Adjustment**	**ECAPM Result**
1	Algonquin Pwr & Util	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$8,126	0.73%	11.5%
2	ALLETE	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.85	75%	6.5%	9.0%	10.4%	$2,800	1.10%	11.5%
3	Alliant Energy	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.85	75%	6.5%	9.0%	10.4%	$13,500	0.50%	10.9%
4	Ameren Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$20,000	0.50%	10.5%
5	Avangrid, Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$15,000	0.50%	10.5%
6	Avista Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$2,400	1.34%	12.1%
7	Black Hills Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.95	75%	7.2%	9.8%	11.2%	$3,800	1.10%	12.3%
8	CMS Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$17,000	0.50%	10.5%
9	Consolidated Edison	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.75	75%	5.7%	8.3%	9.7%	$25,000	0.50%	10.2%
10	DTE Energy Co.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$23,000	0.50%	11.3%
11	Duke Energy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.85	75%	6.5%	9.0%	10.4%	$62,000	-0.28%	10.1%
12	Entergy Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.95	75%	7.2%	9.8%	11.2%	$20,000	0.50%	11.7%
13	Eversource Energy	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$30,000	0.50%	11.3%
14	NorthWestern Corp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$2,700	1.10%	11.9%
15	Pub Sv Enterprise Grp.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$28,000	0.50%	11.3%
16	Sempra Energy	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.95	75%	7.2%	9.8%	11.2%	$35,000	-0.28%	10.9%
17	Southern Company	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.90	75%	6.9%	9.4%	10.8%	$57,000	-0.28%	10.5%
18	WEC Energy Group	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$30,000	0.50%	10.5%
19	Xcel Energy Inc.	2.3%	9.2%	11.6%	1.4%	10.2%	25%	2.5%	0.80	75%	6.1%	8.6%	10.0%	$34,000	-0.28%	9.8%
	Average (f)															**11.0%**
	Midpoint (f) (g)															**11.0%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Oct. 1, 2020).
(b) Average of weighted average earnings growth rates from IBES, Value Line, and Zacks for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Oct. 2, 2020), www.valueline.com (retrieved Oct. 1, 2020), and www.zacks.com (retrieved Oct. 1, 2020).
(c) Average yield on 30-year Treasury bonds for the six-months ending Sep. 2020 based on data from http://www.fred.stlouisfed.org.
(d) Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 190.
(e) The Value Line Investment Survey, Summary & Index (Oct. 9, 2020).
(f) Duff & Phelps, 2020 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(f) Excludes highlighted figures.
(g) Average of low and high values.

CURRENT BOND YIELD

Current Equity Risk Premium	
(a) Avg. Yield over Study Period	8.10%
(b) Average Utility Bond Yield	3.01%
Change in Bond Yield	-5.09%
(c) Risk Premium/Interest Rate Relationship	-0.4210
Adjustment to Average Risk Premium	2.14%
(a) Average Risk Premium over Study Period	3.76%
Adjusted Risk Premium	**5.90%**

Implied Cost of Equity	
(b) Baa Utility Bond Yield	3.37%
Adjusted Equity Risk Premium	5.90%
Risk Premium Cost of Equity	**9.27%**

(a) Exhibit No. 8, page 3.
(b) Average bond yield on all utility bonds and 'Baa' subset for the six-months ending Sep. 2020 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. 8, page 4.

PROJECTED BOND YIELD

Current Equity Risk Premium	
(a) Avg. Yield over Study Period	8.10%
(b) Average Utility Bond Yield 2021-25	4.12%
Change in Bond Yield	-3.98%
(c) Risk Premium/Interest Rate Relationship	-0.4210
Adjustment to Average Risk Premium	1.67%
(a) Average Risk Premium over Study Period	3.76%
Adjusted Risk Premium	**5.43%**

Implied Cost of Equity	
(b) Baa Utility Bond Yield 2021-25	4.79%
Adjusted Equity Risk Premium	5.43%
Risk Premium Cost of Equity	**10.22%**

(a) Exhibit No. 8, page 3.
(b) Yields on all utility bonds and 'A' subset based on data from IHS Markit, Long-Term Macro Forecast - Baseline (May 28, 2020); Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020); & Moody's Investors Service at www.credittrends.com.
(c) Exhibit No. 8, page 4.

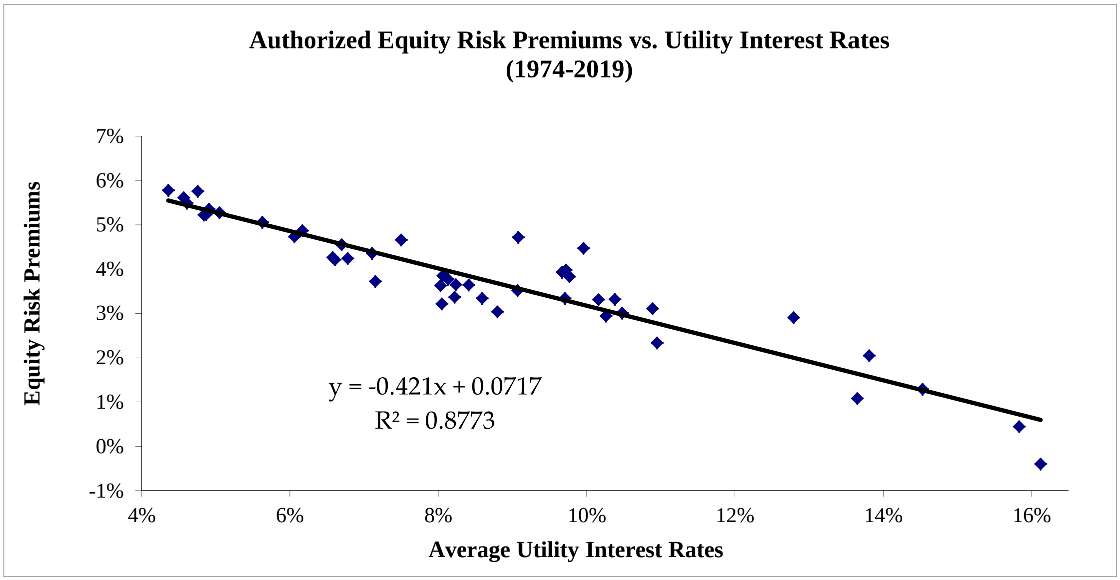
AUTHORIZED RETURNS

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.34%	6.08%	4.26%
2007	10.32%	6.11%	4.21%
2008	10.37%	6.65%	3.72%
2009	10.52%	6.28%	4.24%
2010	10.29%	5.56%	4.73%
2011	10.19%	5.13%	5.06%
2012	10.02%	4.26%	5.76%
2013	9.82%	4.55%	5.27%
2014	9.76%	4.41%	5.35%
2015	9.60%	4.37%	5.23%
2016	9.60%	4.11%	5.49%
2017	9.68%	4.07%	5.61%
2018	9.56%	4.34%	5.22%
2019	9.64%	3.86%	5.78%
Average	**11.86%**	**8.10%**	**3.76%**

(a) Major Rate Case Decisions, *Regulatory Focus* , Regulatory Research Associates ("RRA"); *UtilityScope Regulatory Service* , Argus. Data for "general" rate cases (excluding limited-issue rider cases) beginning in 2006 (the first year such data presented by RRA).

(b) Moody's Investors Service.

REGRESSION RESULTS



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.93662977
R Square	0.87727532
Adjusted R Square	0.87448612
Standard Error	0.00478623
Observations	46

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.007205175	0.007205175	314.5260916	1.15178E-21
Residual	44	0.001007954	2.2908E-05		
Total	45	0.008213129			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.07173108	0.00204844	35.01742055	9.02999E-34	0.06760272	0.07585944	0.06760272	0.075859439
X Variable 1	-0.4210	0.023740031	-17.73488347	1.15178E-21	-0.46887158	-0.3731818	-0.46887158	-0.3731818

EXPECTED EARNINGS APPROACH

UTILITY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Algonquin Pwr & Util	n/a	n/a	n/a
2	ALLETE	8.0%	1.0233	8.2%
3	Alliant Energy	10.5%	1.0150	10.7%
4	Ameren Corp.	10.0%	1.0398	10.4%
5	Avangrid, Inc.	5.0%	1.0048	5.0%
6	Avista Corp.	7.5%	1.0182	7.6%
7	Black Hills Corp.	9.0%	1.0232	9.2%
8	CMS Energy Corp.	13.5%	1.0429	14.1%
9	Consolidated Edison	8.0%	1.0233	8.2%
10	DTE Energy Co.	11.0%	1.0326	11.4%
11	Duke Energy Corp.	8.5%	1.0214	8.7%
12	Entergy Corp.	11.0%	1.0267	11.3%
13	Eversource Energy	9.0%	1.0341	9.3%
14	NorthWestern Corp.	8.5%	1.0169	8.6%
15	Pub Sv Enterprise Grp.	11.0%	1.0249	11.3%
16	Sempra Energy	10.5%	1.0533	11.1%
17	Southern Company	12.5%	1.0188	12.7%
18	WEC Energy Group	12.5%	1.0170	12.7%
19	Xcel Energy Inc.	10.5%	1.0292	10.8%
	Average (d)	**10.1%**		**10.4%**
	Midpoint (d, e)	**10.5%**		**10.9%**

(a) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).
(b) Adjustment to convert year-end return to an average rate of return from Exhibit No. 5.
(c) (a) x (b).
(d) Excludes highlighted figures.
(e) Average of low and high values.

FLOTATION COST STUDY **Exhibit No. 10**

VALUE LINE ELECTRIC INDUSTRY

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
No.	**Sym**	**Company**	**Date**	**Shares Issued**	**Offering Price**	**Underwriting Discount (per share)**	**Underwriting Discount**	**Offering Expense**	**Total Flotation Costs**	**Gross Proceeds Before Flot. Costs**	**Flotation Cost (%)**
1	ALE	ALLETE	2/27/2014	3,220,000	$49.75	$1.74125	$5,606,825	$450,000	$6,056,825	$160,195,000	3.781%
2	LNT	Alliant Energy	11/14/2019	3,717,502	$52.63	$0.39500	$1,468,413	$500,000	$1,968,413	$195,652,130	1.006%
3	AEE	Ameren Corp.	8/5/2019	7,549,205	$74.30	$0.12000	$905,905	$750,000	$1,655,905	$560,905,932	0.295%
4	AEP	American Elec Pwr	4/2/2009	69,000,000	$24.50	$0.73500	$50,715,000	$400,000	$51,115,000	$1,690,500,000	3.024%
5	AGR	Avangrid, Inc.					N/A				
6	AVA	Avista Corp.	12/13/2006	3,162,500	$25.05	$0.48000	$1,518,000	$300,000	$1,818,000	$79,220,625	2.295%
7	BKH	Black Hills Corp.	11/19/2015	6,325,000	$40.25	$1.40875	$8,910,344	$1,200,000	$10,110,344	$254,581,250	3.971%
8	CNP	CenterPoint Energy	9/27/2018	60,550,459	$27.25	$0.75000	$45,412,844	$1,000,000	$46,412,844	$1,650,000,008	2.813%
9	CMS	CMS Energy Corp.	3/31/2005	23,000,000	$12.25	$0.42880	$9,862,400	$325,000	$10,187,400	$281,750,000	3.616%
10	ED	Consolidated Edison (a)	5/7/2019	5,800,000	$84.83	$0.59000	$3,422,000	$400,000	$3,822,000	$492,014,000	0.777%
11	D	Dominion Energy (a)	3/29/2018	20,000,000	$67.33	$1.89420	$37,884,000	$450,000	$38,334,000	$1,346,516,000	2.847%
12	DTE	DTE Energy Co.	10/29/2019	2,400,000	$126.00	$3.15000	$7,560,000	$300,000	$7,860,000	$302,400,000	2.599%
13	DUK	Duke Energy Corp. (a)	11/18/2019	25,000,000	$85.99	$2.66000	$66,500,000	$592,000	$67,092,000	$2,149,750,000	3.121%
14	EIX	Edison International	7/30/2019	28,000,000	$68.50	$1.62688	$45,552,500	$725,000	$46,277,500	$1,918,000,000	2.413%
15	EE	El Paso Electric Co.					N/A				
16	ETR	Entergy Corp.	6/8/2018	13,289,037	$75.25	$0.80000	$10,631,230	$650,000	$11,281,230	$1,000,000,034	1.128%
17	EVRG	Evergy Inc.					N/A				
18	ES	Eversource Energy	5/30/2019	15,600,000	$71.48	$1.69000	$26,364,000	$615,000	$26,979,000	$1,115,088,000	2.419%
19	EXC	Exelon Corp.	6/13/2014	57,500,000	$35.00	$1.05000	$60,375,000	$600,000	$60,975,000	$2,012,500,000	3.030%
20	FE	FirstEnergy Corp.	9/15/2003	32,200,000	$30.00	$0.97500	$31,395,000	$423,000	$31,818,000	$966,000,000	3.294%
21	FTS	Fortis Inc.					N/A				
22	HE	Hawaiian Elec.	3/20/2013	7,000,000	$26.75	$1.00312	$7,021,840	$450,000	$7,471,840	$187,250,000	3.990%
23	IDA	IDACORP, Inc.	12/10/2004	4,025,000	$30.00	$1.20000	$4,830,000	$300,000	$5,130,000	$120,750,000	4.248%
24	MGEE	MGE Energy	9/10/2004	1,265,000	$31.85	$1.03500	$1,309,275	$125,000	$1,434,275	$40,290,250	3.560%
25	NEE	NextEra Energy, Inc. (a)	11/3/2016	13,800,000	$124.00	$1.89000	$26,082,000	$750,000	$26,832,000	$1,711,200,000	1.568%
26	NWE	NorthWestern Corp. (a)	9/30/2015	1,100,000	$51.81	$1.33000	$1,463,000	$1,000,000	$2,463,000	$56,991,000	4.322%
27	OGE	OGE Energy Corp.	8/22/2003	5,324,074	$21.60	$0.79000	$4,206,018	$325,000	$4,531,018	$114,999,998	3.940%
28	OTTR	Otter Tail Corp.					N/A				
29	PNW	Pinnacle West Capital	4/9/2010	6,900,000	$38.00	$1.33000	$9,177,000	$190,000	$9,367,000	$262,200,000	3.572%
30	PNM	PNM Resources	1/7/2020	5,375,000	$47.21	$1.99000	$10,696,250	$750,000	$11,446,250	$253,753,750	4.511%
31	POR	Portland General Elec.	6/13/2013	12,765,000	$29.50	$0.95875	$12,238,444	$600,000	$12,838,444	$376,567,500	3.409%
32	PPL	PPL Corp.	5/10/2018	55,000,000	$27.00	$0.29430	$16,186,500	$1,000,000	$17,186,500	$1,485,000,000	1.157%
33	PEG	Pub Sv Enterprise Grp.	10/2/2003	9,487,500	$41.75	$1.25250	$11,883,094	$350,000	$12,233,094	$396,103,125	3.088%
34	SRE	Sempra Energy	1/5/2018	26,869,158	$107.00	$1.92600	$51,749,998	$1,500,000	$53,249,998	$2,874,999,906	1.852%
35	SO	Southern Company (a)	8/18/2016	32,500,000	$49.30	$1.66000	$53,950,000	$557,000	$54,507,000	$1,602,250,000	3.402%
36	WEC	WEC Energy Group					N/A				
37	XEL	Xcel Energy Inc. (a)	10/30/2019	10,300,000	$62.69	$0.63000	$6,489,000	$650,000	$7,139,000	$645,707,000	1.106%
		Average									**2.779%**

1	ATO	Atmos Energy Corp.	11/30/2018	7,008,087	$92.75	$0.97690	$6,846,200	$1,000,000	$7,846,200	$650,000,069	1.207%
2	CPK	Chesapeake Utilities	9/23/2016	960,488	$62.26	$2.33000	$2,237,937	$162,046	$2,399,983	$59,799,983	4.013%
3	NJR	New Jersey Resources	12/4/2019	5,700,000	$41.25	$1.23750	$7,053,750	$500,000	$7,553,750	$235,125,000	3.213%
4	NI	NiSource Inc.	5/3/2017	N/A	N/A	N/A	$10,000,000	$57,950	$10,057,950	$500,000,000	2.012%
5	NWN	Northwest Nat. Holding Co.	6/4/2019	1,250,000	$67.00	$2.17750	$2,721,875	$400,000	$3,121,875	$83,750,000	3.728%
6	OGS	ONE Gas, Inc.					N/A				
7	SJI	South Jersey Industries	4/20/2018	11,016,949	$29.50	$1.03250	$11,375,000	$700,000	$12,075,000	$324,999,996	3.715%
8	SWX	Southwest Gas	11/28/2018	3,100,000	$75.50	$2.54810	$7,899,110	$600,000	$8,499,110	$234,050,000	3.631%
9	SR	Spire Inc.	5/9/2018	2,000,000	$63.05	$2.10938	$4,218,760	$325,000	$4,543,760	$126,100,000	3.603%
		Average									**3.140%**
		Average - Electric & Gas									**2.853%**

Column Notes:
(1-4) SEC Form 424B for each company.
(5) Column (2) * Column (4)
(6) SEC Form 424B for each company.
(7) Column (5) + Column (6)
(8) Column (2) * Column (3)
(9) Column (7) / Column (8)
Note (a): Underwriting discount computed as the difference between the current market price and the price offered to the issuing company by the underwriters.

DCF MODEL - NON-UTILITY GROUP

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	Air Products & Chem.	Chemical (Diversified)	$ 297.45	$ 5.36	1.8%
2	Amdocs Ltd.	IT Services	$ 58.52	$ 1.31	2.2%
3	Amgen	Biotechnology	$ 247.73	$ 6.85	2.8%
4	Amphenol Corp.	Electronics	$ 108.37	$ 1.00	0.9%
5	Apple Inc.	Computers/Peripherals	$ 115.93	$ 0.85	0.7%
6	AT&T Inc.	Telecom. Services	$ 28.90	$ 2.11	7.3%
7	Baxter Int'l Inc.	Med Supp Invasive	$ 81.50	$ 0.98	1.2%
8	Bristol-Myers Squibb	Drug	$ 59.73	$ 1.80	3.0%
9	Brown & Brown	Financial Svcs. (Div.)	$ 45.28	$ 0.34	0.8%
10	Brown-Forman 'B'	Beverage	$ 76.93	$ 0.72	0.9%
11	Church & Dwight	Household Products	$ 92.70	$ 0.96	1.0%
12	Cisco Systems	Telecom. Equipment	$ 39.85	$ 1.46	3.7%
13	Coca-Cola	Beverage	$ 49.85	$ 1.68	3.4%
14	Colgate-Palmolive	Household Products	$ 77.20	$ 1.76	2.3%
15	Comcast Corp.	Cable TV	$ 45.31	$ 0.92	2.0%
16	Commerce Bancshs.	Bank (Midwest)	$ 57.06	$ 1.08	1.9%
17	Costco Wholesale	Retail Store	$ 349.12	$ 2.80	0.8%
18	CVS Health	Pharmacy Services	$ 58.89	$ 2.00	3.4%
19	Danaher Corp.	Diversified Co.	$ 208.96	$ 0.72	0.3%
20	Gen'l Mills	Automotive	$ 60.54	$ 2.04	3.4%
21	Hormel Foods	Food Processing	$ 49.54	$ 1.00	2.0%
22	Intel Corp.	Hotel/Gaming	$ 50.63	$ 1.32	2.6%
23	Int'l Flavors & Frag.	Wireless Networking	$ 121.07	$ 3.12	2.6%
24	Johnson & Johnson	Med Supp Non-Invasive	$ 148.24	$ 4.04	2.7%
25	Kellogg	Food Processing	$ 65.51	$ 2.30	3.5%
26	Kimberly-Clark	Household Products	$ 149.41	$ 4.28	2.9%
27	Lilly (Eli)	Drug	$ 149.22	$ 2.96	2.0%
28	Lockheed Martin	Aerospace/Defense	$ 386.92	$ 10.40	2.7%
29	Marsh & McLennan	Financial Svcs. (Div.)	$ 115.59	$ 1.86	1.6%
30	McCormick & Co.	Food Processing	$ 196.55	$ 2.50	1.3%
31	McDonald's Corp.	Restaurant	$ 218.94	$ 5.00	2.3%
32	Merck & Co.	Drug	$ 83.37	$ 2.44	2.9%
33	Microsoft Corp.	Computer Software	$ 210.35	$ 2.04	1.0%
34	Northrop Grumman	Aerospace/Defense	$ 330.37	$ 5.80	1.8%
35	Oracle Corp.	Drug	$ 59.01	$ 0.96	1.6%
36	PepsiCo, Inc.	Beverage	$ 136.49	$ 4.09	3.0%
37	Pfizer, Inc.	Drug	$ 36.52	$ 1.52	4.2%
38	Procter & Gamble	Household Products	$ 138.41	$ 3.16	2.3%
39	Public Storage	R.E.I.T.	$ 220.71	$ 8.00	3.6%
40	Texas Instruments	Environmental	$ 141.31	$ 4.08	2.9%
41	Travelers Cos.	Insurance (Prop/Cas.)	$ 112.19	$ 3.40	3.0%
42	United Parcel Serv.	Air Transport	$ 163.97	$ 4.04	2.5%
43	Verizon Communic.	Telecom. Services	$ 59.73	$ 2.51	4.2%
44	Walmart Inc.	Retail Store	$ 139.57	$ 2.18	1.6%
45	Waste Management	Environmental	$ 113.73	$ 2.18	1.9%
	Average				**2.4%**

(a) Average of closing prices for 30 trading days ended Oct. 9, 2020.

(b) The Value Line Investment Survey, *Summary & Index* (Oct. 9, 2020).

DCF MODEL - NON-UTILITY GROUP

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth		
	Company	**V Line**	**IBES**	**Zacks**
1	Air Products & Chem.	12.00%	10.33%	8.77%
2	Amdocs Ltd.	9.50%	4.40%	8.50%
3	Amgen	6.50%	6.87%	7.23%
4	Amphenol Corp.	10.50%	3.00%	7.51%
5	Apple Inc.	15.50%	12.46%	11.00%
6	AT&T Inc.	5.50%	0.29%	5.53%
7	Baxter Int'l Inc.	9.00%	10.00%	9.75%
8	Bristol-Myers Squibb	12.50%	22.20%	8.63%
9	Brown & Brown	10.50%	8.64%	n/a
10	Brown-Forman 'B'	11.00%	6.85%	n/a
11	Church & Dwight	8.00%	9.48%	8.86%
12	Cisco Systems	7.00%	6.18%	6.67%
13	Coca-Cola	6.50%	2.93%	4.81%
14	Colgate-Palmolive	5.00%	5.91%	5.89%
15	Comcast Corp.	8.50%	5.24%	9.76%
16	Commerce Bancshs.	6.50%	-8.70%	n/a
17	Costco Wholesale	9.00%	7.04%	8.37%
18	CVS Health	6.00%	6.34%	5.59%
19	Danaher Corp.	16.00%	13.06%	11.71%
20	Gen'l Mills	3.00%	5.05%	7.50%
21	Hormel Foods	8.50%	1.00%	7.50%
22	Intel Corp.	7.00%	8.62%	7.50%
23	Int'l Flavors & Frag.	8.00%	0.38%	n/a
24	Johnson & Johnson	10.00%	5.09%	5.75%
25	Kellogg	3.00%	1.85%	6.00%
26	Kimberly-Clark	6.50%	6.36%	5.49%
27	Lilly (Eli)	10.00%	13.30%	15.69%
28	Lockheed Martin	8.50%	9.11%	6.93%
29	Marsh & McLennan	9.00%	4.87%	3.05%
30	McCormick & Co.	6.50%	4.80%	5.54%
31	McDonald's Corp.	8.00%	3.98%	7.04%
32	Merck & Co.	9.00%	6.83%	6.74%
33	Microsoft Corp.	15.00%	15.25%	13.71%
34	Northrop Grumman	11.00%	8.62%	n/a
35	Oracle Corp.	10.50%	9.18%	11.00%
36	PepsiCo, Inc.	6.00%	5.90%	6.49%
37	Pfizer, Inc.	8.50%	5.37%	4.29%
38	Procter & Gamble	8.50%	7.15%	6.53%
39	Public Storage	n/a	17.00%	3.36%
40	Texas Instruments	4.00%	10.00%	9.33%
41	Travelers Cos.	9.50%	3.05%	6.66%
42	United Parcel Serv.	6.00%	7.31%	7.90%
43	Verizon Communic.	4.00%	1.64%	3.41%
44	Walmart Inc.	7.50%	6.41%	5.63%
45	Waste Management	5.50%	-1.26%	6.29%

(a) The Value Line Investment Survey (various editions as of Oct. 9, 2020).
(b) www.finance.yahoo.com (retrieved Oct. 11, 2020).
(c) www.zacks.com (retrieved Oct. 11, 2019).

DCF MODEL - NON-UTILITY GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)
		Earnings Growth		
	Company	**V Line**	**IBES**	**Zacks**
1	Air Products & Chem.	13.8%	12.1%	10.6%
2	Amdocs Ltd.	11.7%	6.6%	10.7%
3	Amgen	9.3%	9.6%	10.0%
4	Amphenol Corp.	11.4%	3.9%	8.4%
5	Apple Inc.	16.2%	13.2%	11.7%
6	AT&T Inc.	12.8%	7.6%	12.8%
7	Baxter Int'l Inc.	10.2%	11.2%	11.0%
8	Bristol-Myers Squibb	15.5%	25.2%	11.6%
9	Brown & Brown	11.3%	9.4%	n/a
10	Brown-Forman 'B'	11.9%	7.8%	n/a
11	Church & Dwight	9.0%	10.5%	9.9%
12	Cisco Systems	10.7%	9.8%	10.3%
13	Coca-Cola	9.9%	6.3%	8.2%
14	Colgate-Palmolive	7.3%	8.2%	8.2%
15	Comcast Corp.	10.5%	7.3%	11.8%
16	Commerce Bancshs.	8.4%	-6.8%	n/a
17	Costco Wholesale	9.8%	7.8%	9.2%
18	CVS Health	9.4%	9.7%	9.0%
19	Danaher Corp.	16.3%	13.4%	12.1%
20	Gen'l Mills	6.4%	8.4%	10.9%
21	Hormel Foods	10.5%	3.0%	9.5%
22	Intel Corp.	9.6%	11.2%	10.1%
23	Int'l Flavors & Frag.	10.6%	3.0%	n/a
24	Johnson & Johnson	12.7%	7.8%	8.5%
25	Kellogg	6.5%	5.4%	9.5%
26	Kimberly-Clark	9.4%	9.2%	8.4%
27	Lilly (Eli)	12.0%	15.3%	17.7%
28	Lockheed Martin	11.2%	11.8%	9.6%
29	Marsh & McLennan	10.6%	6.5%	4.7%
30	McCormick & Co.	7.8%	6.1%	6.8%
31	McDonald's Corp.	10.3%	6.3%	9.3%
32	Merck & Co.	11.9%	9.8%	9.7%
33	Microsoft Corp.	16.0%	16.2%	14.7%
34	Northrop Grumman	12.8%	10.4%	n/a
35	Oracle Corp.	12.1%	10.8%	12.6%
36	PepsiCo, Inc.	9.0%	8.9%	9.5%
37	Pfizer, Inc.	12.7%	9.5%	8.5%
38	Procter & Gamble	10.8%	9.4%	8.8%
39	Public Storage	n/a	20.6%	7.0%
40	Texas Instruments	6.9%	12.9%	12.2%
41	Travelers Cos.	12.5%	6.1%	9.7%
42	United Parcel Serv.	8.5%	9.8%	10.4%
43	Verizon Communic.	8.2%	5.8%	7.6%
44	Walmart Inc.	9.1%	8.0%	7.2%
45	Waste Management	7.4%	0.7%	8.2%
	Average (b)	**10.3%**	**9.6%**	**9.7%**
	Midpoint (b,c)	**10.2%**	**9.9%**	**9.8%**

(a) Sum of dividend yield (p. 1) and respective growth rate (p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

CAPITAL STRUCTURE

UTILITY GROUP

		At Year-end 2019 (a)			Value Line Projected (b)		
	Company	**Debt**	**Preferred**	**Common Equity**	**Debt**	**Preferred**	**Common Equity**
1	Algonquin Pwr & Util	47.2%	2.2%	50.6%	n/a	n/a	n/a
2	ALLETE	40.9%	0.0%	59.1%	41.0%	0.0%	59.0%
3	Alliant Energy	53.4%	1.7%	44.9%	52.0%	0.0%	48.0%
4	Ameren Corp.	53.3%	0.0%	46.7%	50.0%	1.0%	49.0%
5	Avangrid, Inc.	32.3%	0.0%	67.7%	42.5%	0.0%	57.5%
6	Avista Corp.	49.4%	0.0%	50.6%	51.0%	0.0%	49.0%
7	Black Hills Corp.	56.1%	0.0%	43.9%	52.0%	0.0%	48.0%
8	CMS Energy Corp.	64.4%	0.0%	35.6%	68.0%	0.0%	32.0%
9	Consolidated Edison	72.2%	0.0%	27.8%	50.0%	0.0%	50.0%
10	DTE Energy Co.	52.3%	0.0%	47.7%	58.5%	0.0%	41.5%
11	Duke Energy Corp.	52.1%	0.0%	47.9%	53.5%	1.5%	45.0%
12	Entergy Corp.	58.4%	0.0%	41.6%	59.5%	1.0%	39.5%
13	Eversource Energy	54.8%	0.0%	45.2%	53.0%	0.5%	46.5%
14	NorthWestern Corp.	63.0%	0.8%	36.2%	50.0%	0.0%	50.0%
15	Pub Sv Enterprise Grp.	53.5%	0.0%	46.5%	50.0%	0.0%	50.0%
16	Sempra Energy	51.3%	0.0%	48.7%	48.5%	0.0%	51.5%
17	Southern Company	52.5%	0.0%	47.5%	60.0%	0.5%	39.5%
18	WEC Energy Group	62.8%	0.0%	37.2%	52.0%	0.0%	48.0%
19	Xcel Energy Inc.	50.0%	0.0%	50.0%	57.5%	0.0%	42.5%
	Average	**53.7%**	**0.2%**	**46.1%**	**52.7%**	**0.3%**	**47.0%**
	Average - Ex. High and Low	**53.8%**	**0.1%**	**45.9%**	**52.5%**	**0.2%**	**47.2%**

(a) Most recent SEC Form 10-K reports.

(b) The Value Line Investment Survey (Jul. 24, Aug. 14 and Sep. 11, 2020).

UTILITY GROUP OPERATING SUBSIDIARIES

	At Year-End 2019 (a)		
Operating Company	**Debt**	**Preferred**	**Common Equity**
ALGONQUIN PWR. & UTIL.			
Empire District Electric Co.	46.0%	0.0%	54.0%
Liberty Utilities (Granite State Elec.)	22.9%	0.0%	77.1%
ALLETE			
ALLETE, Inc. (Minnesota Power)	40.4%	0.0%	59.6%
ALLIANT ENERGY CORP.			
Interstate Power & Light	47.5%	3.0%	49.4%
Wisconsin Power & Light	45.0%	0.0%	55.0%
AMEREN CORP.			
Ameren Illinois Co.	46.4%	0.8%	52.8%
Union Electric Co.	49.1%	0.9%	50.0%
AVANGRID			
Central Maine Pwr	37.5%	0.0%	62.5%
NY State E&G	51.1%	0.0%	48.9%
Rochester G&E	48.8%	0.0%	51.2%
United Illuminating	42.4%	0.0%	57.6%
AVISTA CORP.			
Avista Corp.	49.2%	0.0%	50.8%
Alaska Electric Light & Power	40.2%	0.0%	59.8%
BLACK HILLS CORP.			
Black Hills Power	43.2%	0.0%	56.8%
Cheyenne Light Fuel & Power	51.7%	0.0%	48.3%
Black Hills/Colorado Electric Utility Co	27.0%	0.0%	73.0%
CMS ENERGY			
Consumers Energy Co.	48.7%	0.2%	51.1%
CONSOLIDATED EDISON			
Consolidated Edison of NY	51.4%	0.0%	48.6%
Orange & Rockland	52.0%	0.0%	48.0%
Rockland Electric Co.	0.0%	0.0%	100.0%
DTE ENERGY CO.			
DTE Electric Co.	50.0%	0.0%	50.0%
DUKE ENERGY			
Duke Energy Carolinas	48.2%	0.0%	51.8%
Duke Energy Florida	54.1%	0.0%	45.9%
Duke Energy Indiana	47.0%	0.0%	53.0%
Duke Energy Ohio	41.6%	0.0%	58.4%
Duke Energy Progress	49.5%	0.0%	50.5%
Progress Energy Inc.	55.7%	0.0%	44.3%
Duke Energy Kentucky	50.6%	0.0%	49.4%

UTILITY GROUP OPERATING SUBSIDIARIES

	At Year-End 2019 (a)		
Operating Company	**Debt**	**Preferred**	**Common Equity**
ENTERGY CORP.			
Entergy Arkansas Inc.	52.9%	0.0%	47.1%
Entergy Louisiana LLC	53.3%	0.0%	46.7%
Entergy Mississippi Inc.	51.1%	0.0%	48.9%
Entergy New Orleans Inc.	52.9%	0.0%	47.1%
Entergy Texas Inc.	51.7%	0.9%	47.4%
EVERSOURCE ENERGY			
Connecticut Light & Power	43.9%	1.4%	54.7%
NSTAR Electric Co.	44.3%	0.6%	55.1%
Public Service Co. of New Hampshire	52.4%	0.0%	47.6%
NORTHWESTERN CORP.			
NorthWestern Corporation	52.4%	0.0%	47.6%
PUB SV ENTERPRISE GRP			
Pub Service Electric & Gas Co.	45.2%	0.0%	54.8%
SEMPRA ENERGY			
San Diego Gas & Electric	47.3%	0.0%	52.7%
Oncor Electric Delivery	43.4%	0.0%	56.6%
SOUTHERN CO.			
Alabama Power Co.	48.0%	1.6%	50.4%
Georgia Power Co.	44.0%	0.0%	56.0%
Mississippi Power Co.	49.0%	0.0%	51.0%
WEC ENERGY GROUP			
Wisconsin Electric Power Co.	43.5%	0.5%	56.0%
Wisconsin Public Service Corp.	45.4%	0.0%	54.6%
XCEL ENERGY, INC.			
Northern States Power Co. (MN)	47.8%	0.0%	52.2%
Northern States Power Co. (WI)	45.8%	0.0%	54.2%
Public Service Co. of Colorado	43.7%	0.0%	56.3%
Southwestern Public Service Co.	45.9%	0.0%	54.1%
Minimum	**22.9%**	**0.0%**	**44.3%**
Maximum	**55.7%**	**3.0%**	**77.1%**
Average	**46.7%**	**0.2%**	**53.1%**

(a) Data from year-end 2019 Company 10-Ks and FERC Form 1 reports.

(b) Excludes Rockland Electric Co.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	**)**	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	**)**	**CASE NO. 2020-00350**

TESTIMONY OF
CHRISTOPHER M. GARRETT
CONTROLLER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

TABLE OF CONTENTS

I. BACKGROUND

Q. Please state your name, position, and business address.

A. My name is Christopher M. Garrett. I am the Controller for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively, the "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in numerous proceedings before the Commission. Most recently, I testified in KU's and LG&E's 2018 base rate cases.[1]

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to present certain schedules required by 807 KAR 5:001 Section 16 filed with the Companies' applications; (2) describe the calculation of KU's and LG&E's adjusted net operating income and revenue deficiency for the 12-month forecasted test period; (3) to explain certain pro forma adjustments to each revenue requirement calculation; (4) to describe the need to establish or update certain regulatory assets and liabilities; and (5) to provide an overview of why the Companies are filing depreciation studies.

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[1] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Testimony of Christopher M. Garrett (Ky. PSC Sept. 28, 2018); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates,* Case No. 2018-00295, Testimony of Christopher M. Garrett (Ky. PSC Sept. 28, 2018).

II. SCHEDULES REQUIRED BY 807 KAR 5:001, SECTION 16(7)

Q. Are you sponsoring certain information required by the Commission's regulation 807 KAR 5:001 Section 16(7)?

A. Yes, I am sponsoring the following information for the corresponding filing requirements for each of the Companies:

• Most recent FERC or FCC audit reports	Section 16(7)(i)	Tab 39
• Most recent FERC Form 1 (electric), FERC Form 2 (gas), or PSC Form T (telephone)	Section 16(7)(k)	Tab 41
• Annual report to shareholders and statistical supplements	Section 16(7)(l)	Tab 42
• Current chart of accounts	Section 16(7)(m)	Tab 43
• SEC annual reports (Form 10-Ks, Form 8-Ks, and Form 10-Qs)	Section 16(7)(p)	Tab 46
• Independent auditor's annual opinion report, with any written communication from the auditor which indicates the existence of a material weakness in internal controls	Section 16(7)(q)	Tab 47
• Quarterly reports to stockholders for most recent five quarters	Section 16(7)(r)	Tab 48
• Summary of utility's latest depreciation study with schedules by major plant accounts	Section 16(7)(s)	Tab 49
• Information related to any amounts charged, allocated, or paid to utility by an affiliate or general or home office	Section 16(7)(u)	Tab 51

III. SCHEDULES REQUIRED BY 807 KAR 5:001, SECTION 16(8)

Q. Are you sponsoring certain information required by the Commission's regulation 807 KAR 5:001 Section 16(8)?

A. Yes, I am sponsoring the following information for the corresponding filing requirements for each of the Companies:

• Jurisdictional financial summary for base and forecasted periods	Section 16(8)(a)	Tab 54
• Jurisdictional rate base summary for base and forecasted periods	Section 16(8)(b)	Tab 55
• Jurisdictional operating income summary for base and forecasted periods	Section 16(8)(c)	Tab 56
• Summary of jurisdictional adjustments to operating income	Section 16(8)(d)	Tab 57
• Jurisdictional federal and state income tax summary	Section 16(8)(e)	Tab 58
• Summary schedules for base and forecasted periods of organizational membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases	Section 16(8)(f)	Tab 59
• Computation of gross revenue conversion factor for forecasted period	Section 16(8)(h)	Tab 61

IV. PROPERTY VALUATIONS PRESENTED: CAPITALIZATION AND RATE BASE

Q. Are you sponsoring certain information required by the Commission's regulation 807 KAR 5:001 Section 16(6)?

A. Yes, I am sponsoring all information required by 807 KAR 5:001 Section 16(6)(f) for each of the Companies.

Q. What are the property valuation measures to be considered by the Commission for ratemaking purposes?

A. Section 278.290 of the Kentucky Revised Statutes requires the Commission to give due consideration to three quantifiable values: original cost (rate base), cost of reproduction as a going concern, and capital structure. The Commission is also required to consider the history and development of the utilities and their property and other elements of value long recognized for ratemaking purposes.

Q. Which property-valuation methodology have the Companies chosen to support their requested rate changes in these cases?

A. The calculation of the Companies' rate base and capitalization valuations are shown on Section 16(8)(b) and (j) at Tabs 55 and 63 filed with each Company's application. Continuing with the Companies' approach in their seven most recent base rate cases, the Companies have chosen the capitalization methodology of property valuation. The Commission approved this approach in each of those base rate cases.

Q. Has the Commission indicated a preference for the utility to continue using the property valuation methodology it has historically used?

A. Yes. The Commission has stated that it "will consider using an approach different than that previously used" only if a justification exists. For example, in Case No. 2000-00080, the Commission considered whether LG&E had presented sufficient evidence to support changing the property valuation methodology it had traditionally used.[2] Here sufficient justification does not exist to support departing from the more than 40 years of using the capitalization valuation methodology to use the rate base property valuation methodology in these cases.

[2] *The Application of Louisville Gas & Electric Company to Adjust and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-00080, Order at 9 (Ky. PSC Sept. 27, 2000).

Q. Has the Commission indicated a preference for the use of capitalization instead of rate base?

A. Yes, the Commission stated:

> The capitalization of the utility is a better measure of the real cost of providing service since it is the cost of debt and equity that is reflected in the financial statements of the utility. To impute the operating income requirements based on an inflated rate base in effect establishes a cost of doing business that is non-existent to the utility.[3]

Q. Please compare the Companies' property valuation methodologies.

A. As detailed below, the Companies acknowledge that capitalization is slightly higher than rate base in this proceeding, i.e., less than 1% for KU, LG&E Electric, and LG&E Gas. The fact that capitalization slightly exceeds rate base does not require the Companies to abandon their longstanding capitalization valuation methodology to use rate base. The Commission has approved the use of a property valuation methodology even when it produced a higher property valuation.[4] In fact, the Commission approved the Companies' capitalization valuation methodology in their last base rate cases when capitalization exceeded rate base.[5]

Q. Does capitalization remain the most objective measure of property valuation for the Companies?

A. Yes. The Companies believe capitalization continues to be the most objective measure of valuation given the Companies' lack of unregulated activities. As the Commission

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[3] *Id.* at 11.
[4] *See, e.g.*, Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019); *An Adjustment of General Rates of Delta Natural Gas Company, Inc.*, Case No. 1997-00066, Order (Ky. PSC May 1, 1998) (determining revenue requirements by using rate base, even though it was higher than capitalization).
[5] *See* Case Nos. 2018-00294 and 2018-00295, Rebuttal Testimony of Christopher M. Garrett at 6 (Ky. PSC Feb. 22, 2019) (KU's capitalization exceeded rate base by 0.61%; LG&E Electric's capitalization exceeded rate base by 1.30%; LG&E Gas's capitalization exceeded rate base by 1.29%).

has observed, while rate base and capitalization theoretically should be equal, it is rare that this happens.[6] When a utility's capitalization exceeds rate base, it raises concerns that a portion of the capitalization has been used to finance non-regulated activities.[7] For the Companies, though, that is not the case. This fact is confirmed by the Companies' recent nonregulated operations annual filings.[8] Therefore, the Companies see no reason to change their valuation methodologies under these circumstances.

Q. Do you have a reconciliation of capitalization versus rate base?

A. Yes. A reconciliation of the two valuation amounts is located at Tab 13 as part of filing requirement 16(6)(f). The reconciliation demonstrates capitalization exceeds rate base by $37,918,411 (0.73%) for KU, $7,194,618 (0.21%) for LG&E Electric, and $9,456,118 (0.90%) for LG&E Gas.

Q. Are the Companies proposing any new adjustments to capitalization in this proceeding?

A. Yes, the Companies have included two new adjustments to capitalization in this proceeding. First, the Companies have adjusted capitalization for the proration of accumulated deferred income taxes in accordance with §1.1167(l)-1(h)(6) of the Internal Revenue Code. Second, the Companies have adjusted capitalization to remove the impacts associated with the Advanced Metering Infrastructure ("AMI") project.

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[6] *Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of its Rate and Service*, Case No. 1998-00426, Order at 3 (Ky. PSC June 1, 1998).
[7] *The Application of Louisville Gas & Electric Company to Adjust and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-00080, Order at 5 (Ky. PSC Sept. 27, 2000).
[8] KU's Annual Report of Nonregulated Activities required by 807 KAR 5:080 for calendar year 2019 shows that KU's nonregulated activities make up only 0.00043% of total revenue. LG&E's Annual Report of Nonregulated Activities required by 807 KAR 5:080 for calendar year 2019 shows that LG&E's nonregulated activities make up only 0.16224% of total revenue.

The proposed accounting for AMI is detailed in Kent W. Blake's testimony. These two adjustments are reflected on Schedule J-1.1 and J-1.2.

Q. Have the Companies considered using the cost of reproduction as a going concern valuation methodology in this case?

A. No. The Commission has consistently found such methodology was not the most appropriate or reasonable measure for rate of return valuation.[9] This methodology typically leads to a significantly higher revenue requirement than the capitalization or rate base methodologies.[10] Moreover, following the United States Supreme Court's severe criticism of the use of this methodology for ratemaking purposes nearly 100 years ago, state regulatory commissions have declined to use the cost of reproduction

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[9] *See, e.g.*, *General Adjustment of Rates of Kentucky Utilities Company*, Case No. 7804, Order at 2 (Ky. PSC Oct. 1, 1980) ("KU presented the net original cost, capital structure, and reproduction cost as the valuation methods in this case. The Commission has given due consideration to these and other elements of value in determining the reasonableness of the proposed rates and charges. As in the past, the Commission has given limited consideration to the proposed reproduction cost."); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 7799, Order at 6 (Ky. PSC Sept. 24, 1980) at 6 ("[A]s this [cost of reproduction] method is not conclusive to present value, the Commission, though recognizing this valuation as a lawful one, gave less consideration to it than to others it deemed would result in a more reasonable rate to the consumer and yet a reasonable rate of return to the investor"); *General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8177, Order at 9-10 (Ky. PSC Sept. 11, 1981); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8284, Order at 2 (Ky. PSC Jan. 4, 1982); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8616, Order at 4 (Ky. PSC Mar. 2, 1983); *General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8624, Order at 2 (Ky. PSC Mar. 18, 1983); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8924, Order at 3 (Ky. PSC May 16, 1984); *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8924, Order at 3 (Ky. PSC May 16, 1984); *An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 15 (Ky. PSC June 30, 2004); *An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 17 (Ky. PSC June 30, 2004); *Application of Kentucky Utilities Company For An Adjustment of Electric Base Rates*, Case No. 2008-00251, Order at 16-17 (Ky. PSC Feb. 5, 2009); *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 18 (Ky. PSC July 30, 2010).

[10] *See An Adjustment of the Rates of Elzie Neeley Gas Company*, Case No. 90-076, Order at 3 (Ky. PSC Dec. 7, 1990) (noting that reproduction cost appraisal inflates a utility's rate base, results in a valuation that has no economic substance, and could result in rates that are excessive in relation to the actual investment made by the owners of the utility). *See also The Application of Western Kentucky Gas Company For Authority to Adjust Its Rates*, Case No. 8227, Order at 3 (Ky. PSC Oct. 9, 1981) ("[N]et original cost, net investment and capital structure valuation methods are still the most prudent, efficient and economical measures of reasonable rate of return valuation.").

method for many years.[11] In light of this extensive precedent, the Companies believe presenting the reproduction methodology's results and raising the methodology's use as an issue for the Commission's review and consideration in detail will not result in a productive or efficient use of the Commission's limited resources or those of any intervening party. The Commission's consideration of this evidence and past practice should be sufficient in light of this extensive precedent.

V. FORECASTED TEST PERIOD

Q. What is the forecasted test period the Companies used for supporting the requested increases in revenue for their operations in these cases?

A. The forecasted test period begins July 1, 2021 and ends June 30, 2022.

Q. What is the base period the Companies used for purposes of their base rate applications in these cases?

A. The base period is the 12-month period ending February 28, 2021 and consists of six months of actual data from March 1, 2020 to August 31, 2020 and six months of forecasted data from September 1, 2020 to February 28, 2021. KU and LG&E expect to file updated information, any corrections, and the actual data from March 1, 2020 to February 28, 2021 with the Commission no later than April 14, 2021 or 45 days after the end of the base period.

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[11] *See, e.g., State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri*, 262 U.S. 276, 301 (1923) (Brandeis, J. concurring) ("[The] conviction is wide-spread that a sound conclusion as to the actual value of a utility is not to be reached by a meticulous study of conflicting estimates of the cost of reproducing new the congeries of old machinery and equipment, called the plant, and the still more fanciful estimates concerning the value of the intangible elements of an established business."). *See also St. Joseph Stock Yards Co. v. U.S.*, 298 U.S. 38 (1936); *Federal Power Commission v. Natural Gas Pipeline Co. of America*, 315 U.S. 575 (1942).

VI. CALCULATION OF JURISDICTIONAL REVENUE DEFICIENCY

Q. Have each of the Companies prepared jurisdictional financial summaries of their jurisdictional operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(a)?

A. Yes. Each of the Companies has prepared this information ("Schedule A"). Schedule A is located at Tab 54 to each application and shows how KU and LG&E determined the amount of the requested revenue increases for KU's jurisdictional operations and LG&E's electric and gas operations. A description of how the jurisdictional financial summary was prepared is contained in Appendix B – Rate Schedule to my testimony.

A. KU's Calculation of Revenue Deficiency

Q. What does KU's financial summary on Schedule A show?

A. The financial summary for KU's jurisdictional operations shows that KU's jurisdictional operations, at current rates, will incur a projected revenue deficiency of $170,477,290 for the forecasted test period, the 12-month period ending June 30, 2022. The projected revenue deficiency is based upon a required rate of return on capital of 7.21 percent. During the forecasted test period at current rates, KU's jurisdictional operations are projected to earn a rate of return of only 4.77 percent.

The revenue increase requested for KU's jurisdictional operations of $170,120,598 includes a revenue adjustment of $353,856 as shown on Schedule M-2.1 to ensure that the under-recovery associated with the rate changes to the solar share, business solar, and electric vehicle charging programs is not borne by other customers. This is discussed in the testimony of William Steven Seelye, the managing partner for The Prime Group, LLC.

Q. How do the results for the forecasted test period compare to the base period?

A. For the base period, which ends February 28, 2021, KU's operations are expected to have a revenue deficiency of $49,134,906 and an earned rate of return on capital of 6.39 percent. During the forecasted test period, the revenue deficiency for KU's jurisdictional operations is projected to increase and its earned rate of return on capital is projected to further decline.

B. LG&E Electric's Calculation of Revenue Deficiency

Q. What does LG&E's financial summary on Schedule A show for LG&E's electric operations?

A. The financial summary for LG&E's electric operations shows that LG&E's electric operations at current rates will incur a projected revenue deficiency of $131,237,389 for the forecasted test period, the 12-month period ending June 30, 2022. The projected revenue deficiency is based upon a required rate of return on capital of 7.17 percent. During the forecasted test period at current rates, LG&E's electric operations are projected to earn a rate of return of only 4.34 percent.

The revenue increase requested for LG&E's electric operations of $131,073,276 includes a revenue adjustment of $175,526 as shown on Schedule M-2.1-E to ensure that the under-recovery associated with the rate changes to the solar share, business solar, and electric vehicle charging programs is not borne by other customers. This is discussed in the testimony of Mr. Seelye.

Q. How do the results for the forecasted test period compare to the base period?

A. For the base period, which ends February 28, 2021, LG&E's electric operations are expected to have a revenue deficiency of $25,743,639 and an earned rate of return on capital of 6.43 percent. During the forecasted test period, the revenue deficiency is projected to increase and its earned rate of return on capital is projected to further decline.

C. LG&E Gas's Calculation of Revenue Deficiency

Q. What does LG&E's financial summary on Schedule A show for LG&E's gas operations?

A. The financial summary for LG&E's gas operations shows that LG&E's gas operations at current rates will incur a projected revenue deficiency of $29,989,470 for the forecasted test period, the 12-month period ending June 30, 2022. The projected revenue deficiency is based upon a required rate of return on capital of 7.17 percent. During the forecasted test period at current rates, LG&E's gas operations are projected to earn a rate of return of only 5.05 percent.

Q. How do the results for the forecasted test period compare to the base period?

A. For the base period, which ends February 28, 2021, LG&E's gas operations are expected to have a revenue deficiency of $6,390,702 and an earned rate of return on capital of 6.56 percent. During the forecasted test period, the revenue deficiency for LG&E's gas operations is projected to increase and its earned rate of return on capital is projected to further decline

VII. JURISDICTIONAL RATE BASE SUMMARY

Q. Have the Companies each prepared a jurisdictional rate base summary of their utility operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(b)?

A. Yes. The Companies have each prepared Schedule B to satisfy the requirements of 807 KAR 5:001 Section 16(8)(b); these schedules are located at Tab 55 of each application. The information contained in Schedule B provides each company's net original cost rate base property as required under KRS 278.290. The calculated rate base amounts are for the base period and for a 13-month average for the forecasted test period as required by 807 KAR 5:001 Section 16(6)(c).

Q. Have you prepared a description of the components of Schedule B?

A. Yes. This description is shown in Appendix C – Rate Schedule to my testimony.

Q. Please explain the adjustments to base period and forecasted test period rate base shown in Schedules B-2.2 and B-4.1.

A. Schedules B-2.2 and 4.1 remove from KU's and LG&E's rate base amounts the portions of rate base for which the Companies' other rate mechanisms provide a recovery of and a return on the utility's investment. For KU and LG&E Electric, these mechanisms are the Demand Side Management ("DSM") cost-recovery mechanism and the Environmental Cost Recovery ("ECR") surcharge. For LG&E Gas, these mechanisms are the DSM cost-recovery mechanism and the Gas Line Tracker ("GLT").

Schedule B-2.2 further removes Asset Retirement Obligation ("ARO") assets from rate base, which is consistent with KU's and LG&E's approach in their prior base rate cases.[12] Appendix D – ARO Assets further describes the Companies' treatment of ARO assets in previous cases.

Q. Are the Companies excluding other amounts from rate base?

A. Yes. The Companies have removed amounts relating to the proposed AMI project from rate base on Schedule B-4.1.

[12] Asset retirement obligations associated with Coal Combustion Residuals ("CCR") closures are included as part of the Unamortized Closure Costs addition to rate base on Schedule B-6 and subsequently removed via the ECR rate base adjustment. CCR closure costs were approved for recovery through the ECR mechanism in Case Nos. 2016-00026 and 2016-00027.

Q. Did KU conduct a jurisdictional separation study?

A. Yes. Mr. Seelye supervised the preparation of a Kentucky jurisdictional separation study for the forecasted test period that generated the Kentucky-jurisdictional allocation factors shown on Schedule B-7.

Q. In summary, what does Schedule B show?

A. For KU, Schedule B shows that KU's jurisdictional rate base for the base period will be $4,281,710,092 which will increase to a 13-month average of $5,197,832,025 for the forecasted test period. When the adjusted operating income shown in Schedule A for the forecasted test period of $249,974,531 is divided by the 13-month-average rate base for the same period, the result is that KU's utility operation will produce a rate of return on average rate base of 4.81 percent. If the Commission approves the requested increase and KU's utility operation earns its required operating income shown in Schedule A for the forecasted test period of $377,286,977 it will earn a rate of return on average rate base of 7.26 percent.

For LG&E's electric operations, Schedule B shows that LG&E's rate base for its electric operations for the base period will be $2,659,979,956 which will increase to a 13-month average of $3,460,077,817 for the forecasted test period. Applying the adjusted operating income shown in Schedule A for the forecasted test period of $150,339,126 to the 13-month-average rate base for the same period produces a rate of return on rate base of 4.34 percent for LG&E's electric operations. If the Commission approves the requested increase and LG&E's electric operations earns its required operating income shown in Schedule A for the forecasted test period of $248,435,857, it will earn a rate of return on average rate base of 7.18 percent.

For LG&E's gas operations, Schedule B shows that LG&E's rate base for the base period will be $898,953,471 which will increase to a 13-month average of $1,052,349,977 for the forecasted test period. Applying the adjusted operating income shown in Schedule A for the forecasted test period $53,663,785 to the 13-month-average rate base for the same period produces a rate of return on rate base of 5.10 percent for LG&E's gas operations. If the Commission approves the requested increase and LG&E's gas operations earns its required operating income shown in Schedule A for the forecasted test period of $76,080,179 it will earn a rate of return on average rate base of 7.23 percent.

VIII. <u>LEAD-LAG STUDIES</u>

Q. Have KU and LG&E performed lead-lag studies?

A. Yes. The Companies are submitting three separate lead-lag studies for KU, LG&E Electric, and LG&E Gas. These lead-lag studies are sponsored by and attached to the testimony of Mr. Seelye.

Q. Please describe the lead-lag studies.

A. The lead-lag studies were conducted to determine the allowance for cash working capital to be included in rate base. The lead-lag studies consist of two sections: the income statement analysis and the balance sheet analysis. Mr. Seelye updated the revenue lag portion but did not update the expense lead portions of the studies. I updated the balance sheet analyses.

Q. Why did the Companies decide not to update the expense portion of the studies?

A. The Companies believe that a five-year period is a reasonable time period to update a lead-lag study. The Companies' position on only updating the revenue portions of the studies is supported by guidance from the Virginia State Corporation Commission, which states that "[u]tilities required to use a lead/lag study should perform a complete lead/lag analysis every five years. Major items such as the revenue lag and balance sheet accounts should be reviewed every year."[13] In addition, the expense lead days require significant time and effort to calculate.

Q. Do the Companies accept the results of the lead-lag studies sponsored by Mr. Seelye?

A. Yes. Mr. Seelye utilized a methodology consistent with that used in KU's most recent Virginia rate case filing and the Companies' 2018 Kentucky rate case proceedings.[14] The Companies note that Mr. Seelye's studies are principally focused on the income statement analyses of cash working capital. I am supporting the balance sheet analyses of cash working capital, which represent amounts from the Companies' forecast. Mr. Seelye explains the income statement analyses and the overall results of the lead-lag days in his testimony.

Q. What accounts were included in the balance sheet analyses of the cash working capital?

A. The balance sheet analyses included certain deferred debits and credits, miscellaneous liabilities, and pension and other employee benefit accounts not otherwise included in the income statement. The balance sheet analyses also include adjustments for capital expenditure accruals.

Q. Are there any key findings from the balance sheet analyses of cash working capital that you would like to discuss?

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[13] 20 VAC 5-201-90.

[14] *Kentucky Utilities Company d/b/a Old Dominion Power Company For an Adjustment of Electric Base Rates*, Case No. PUR-2019-00060, Direct Testimony of Christopher M. Garrett (VSCC filed July 12, 2019); Case Nos. 2018-00294 and 2018-00295, Direct Testimony of Christopher M. Garrett (Ky. PSC Sept. 28, 2018).

A. Yes. As shown on Schedule B-5.2, the balance sheet analyses show a Kentucky jurisdictional net cash working capital component for the forecasted test periods of $73,749,576 for KU, $93,475,992 for LG&E Electric, and $27,654,173 for LG&E Gas including the funding of the pension plan. Pension expense was included in the income statement analyses with an expense lead of zero days because it is a balance sheet item.

Q. Are the Companies using the results of the lead-lag studies to determine the cash working capital component of rate base?

A. Yes. The Companies are using the results of the lead-lag studies to determine the cash working capital component of rate base consistent with the approach used in their last base rate cases.

IX. JURISDICTIONAL OPERATING INCOME SUMMARY

Q. Have the Companies each prepared a jurisdictional operating income summary of their operations for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(c)?

A. Yes. This information ("Schedule C") is located at Tab 56 to each application. LG&E has prepared a Schedule C for each of its utility operations.

Q. Briefly describe Schedule C.

A. Schedule C is a jurisdictional operating income summary for the base period and the forecasted test period with supporting schedules that are broken down by major account group and by individual account. It consists of four schedules:

- Schedule C-1 (Jurisdictional Operating Income Summary)
- Schedule C-2 (Jurisdictional Adjusted Operating Income Statement)
- Schedule C-2.1 (Jurisdictional Operating Revenues and Expenses By Account)

- Schedule C-2.2 (Comparison of Total Company Activity for KU and Comparison of Electric/Gas Utility Activity for LG&E)

A description of the components of Operations Schedules C-1, C-2, C-2.1, and C-2.2 are included in Appendix E – Rate Schedule to my testimony.

A. KU's Jurisdictional Operating Income Summary

Q. What does KU's Schedule C-1 show?

A. Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. Revenues will increase by $170,120,598 for KU. This increase in revenue is equal to the amount of the "Revenue Increase Requested" reported on Schedule A. Expenses will increase by $43,074,529 for KU.

Schedule C-1, Column 5 reflects projected revenues and expenses for the forecasted test period at the utility's proposed rates. For the base period, KU projects total net operating income of $276,159,477, which results in a return on capitalization of 6.39 percent. Total net operating income during the forecasted test period is projected to decrease to $249,974,531. KU's rate of return on capitalization will decrease during the forecasted test period to 4.77 percent unless rates are increased.

B. LG&E Electric's Jurisdictional Operating Income Summary

Q. What does LG&E Electric's Schedule C-1 show?

A. Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. Revenues will increase by $131,073,276 for LG&E Electric. This increase in revenue is equal to the amount of the "Revenue Increase Requested" reported on Schedule A. Expenses will increase by $33,099,216 for LG&E Electric.

Schedule C-1, Column 5 reflects projected revenues and expenses for the forecasted test period at the utility's proposed rates. For the base period, LG&E projects total electric net operating income of $175,965,756, which results in a return on capitalization of 6.43 percent. Total electric net operating income during the forecasted test period is projected to decrease to $150,339,126. LG&E Electric's rate of return on capitalization will decrease during the forecasted test period to 4.34 percent unless rates are increased.

C. LG&E Gas's Jurisdictional Operating Income Summary

Q. What does LG&E Gas's Schedule C-1 show?

A. Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. Revenues will increase by $29,988,054 for LG&E Gas. This increase in revenue is equal to the amount of the "Revenue Increase Requested" reported on Schedule A. Expenses will increase by $7,572,719 for LG&E Gas.

Schedule C-1, Column 5 reflects projected revenues and expenses for the forecasted test period at the utility's proposed rates. For the base period, LG&E projects total gas net operating income of $55,323,680 which results in a return on capitalization of 6.56 percent. Total gas net operating income during the forecasted test period is projected to decrease to $53,663,785. LG&E Gas's rate of return on capitalization will decrease during the forecasted test period to 5.05 percent unless rates are increased.

X. OPERATING INCOME COMPARISON

Q. Have the Companies prepared jurisdictional adjustments to operating income by major account for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(d)?

A. Yes. This information ("Schedule D") with supporting schedules is located at Tab 57 to the application. Schedule D provides the required comparisons between the base period and the forecasted test period.

Q. Please summarize Schedule D.

A. Schedule D is comprised of three schedules. Schedule D-1 shows operating revenue and expenses by account, for both the base period and the forecasted test period and the level of variance between the two with explanations noted. Certain jurisdictional pro forma adjustments are then applied to the forecasted test period to derive the pro forma forecasted test period used in Schedule C.

Schedule D-2 provides the adjustments for both the base period and the forecasted test period to operating revenues and expenses by Federal Energy Regulatory Commission ("FERC") account necessary to remove the effects of the Companies' recovery mechanisms: FAC, OSS, ECR, and DSM. Additionally, an adjustment has been made to remove the effects of the Economic Relief Surcredit. Lastly, an interest synchronization adjustment is made to remove the tax benefit for the deduction of interest of debt capitalization associated with capital projects recovered through the rate mechanisms. The amounts shown in the "Jurisdictional Adjustments" column appear in Column 4 of Schedule C-2.1 in the column "Jurisdictional Adjustments Sch D-2." These adjustments are discussed in further detail below as well as in Appendix G of my testimony.

Schedule D-2.1 provides the pro forma adjustments to operating revenues and expenses by FERC account the Companies are proposing in this proceeding for the forecasted test period. The amounts shown in the "Jurisdictional Pro Forma Adjustments to Forecast Period" column appear in Column 4 of Schedule D-1 in the column "Jurisdictional Pro Forma Adjustments to Forecasted Period." A description of the components of Schedule D are included in Appendix F – Rate Schedule to my testimony.

XI. EFFECT OF CERTAIN RATEMAKING MECHANISMS ON REQUESTED RATE INCREASES

Q. What effect, if any, do ratemaking mechanisms such as the FAC, off-system sales adjustment clause ("OSS"), ECR, DSM, and GLT have on the base rate increases the Companies are requesting?

A. As discussed in my summary of Schedule D in the section above and consistent with the Companies' treatment of the mechanisms in past rate cases,[15] the impact of those mechanisms has been removed from the calculation of the Companies' operating revenues and expenses for both the base period ending February 28, 2021 and the forecasted test period ending June 30, 2022. The mechanisms and the costs and revenues associated with them, therefore, have no effect on the calculation of the revenue deficiency and corresponding base rate increases the Companies are requesting in this case. However, ECR costs allocated to intercompany and off-system sales are

[15] Case Nos. 2018-00294 and 2018-00295, Testimony of Christopher M. Garrett at 20-21 (Ky. PSC Sept. 28, 2018); Case Nos. 2016-00370 and 2016-00371, Testimony of Christopher M. Garrett at 17 (Ky. PSC Nov. 23, 2016).

recovered through base rates rather than the mechanism as discussed in Appendix G. Most importantly, there is no double recovery of these costs.

XII. JURISDICTIONAL ADJUSTMENTS TO OPERATING INCOME

Q. Do KU and LG&E propose similar pro forma adjustments for their revenue requirements?

A. Yes. KU and LG&E Electric are proposing the same pro forma adjustments as proposed in previous rate cases with three exceptions for the following new adjustments: The Economic Relief Surcredit, Pole Revenues, and Industrial Coal Services Revenues, which are discussed below. The proposed LG&E Gas pro forma adjustments are consistent with those proposed in the past with no exceptions. All of the pro forma adjustments which have been consistently applied are described in greater detail in Appendix G.

Q. Why are KU and LG&E proposing a new pro forma adjustment for the Economic Relief Surcredit in this proceeding?

A. The Economic Relief Surcredit will provide customers a one-year bill surcredit as discussed in the testimonies of Kent W. Blake and Robert M. Conroy. Because the surcredit is a separate one-year billing adjustment, the Companies have made a pro forma adjustment to remove the revenues and offsetting income tax expenses of the surcredit from the base rate increases proposed in this proceeding. The adjustments are shown on Schedule D-2 (Adj. 5 for KU and LG&E Electric and Adj. 4 for LG&E Gas) with the supporting details contained in Schedule WPD-2.

Q. Why are KU and LG&E proposing a new pro forma adjustment for Pole Revenues in this proceeding?

A. The Companies are proposing "Adj 9 Pole Revenues" shown on Schedule D-2.1 to include pole attachment revenues that were inadvertently omitted in the forecasted period. The supporting details are contained in Schedule WPD-2.1.

Q. Why is LG&E proposing a new pro forma adjustment for Industrial Coal Services Revenues in this proceeding?

A. LG&E is proposing "Adj 10 Industrial Coal Services Revenues" shown on Schedule D-2.1 to include the revenues and expenses associated with coal logistical services performed for a large industrial customer previously recorded above-the-line and now recorded below-the-line due to a change in accounting made in 2019. The change in accounting was necessitated by the reporting of these services on the annual nonregulated activities report. The supporting details are contained in Schedule WPD-2.1.

Q. Have the Companies prepared jurisdictional federal and state income tax summaries for both base and forecasted test periods as required by 807 KAR 5:001 Section 16(8)(e)?

A. Yes. This information ("Schedule E") is located in Tab 58 to the application. A Schedule E was prepared for KU, LG&E Electric, and LG&E Gas.

Q. Please describe Schedule E.

A. Schedule E has two parts: Schedule E-1 shows the company's jurisdictional income tax at current rates for the base period and shows pro forma adjustments at both current and proposed rates for the forecasted test period; Schedule E-2 shows how the jurisdictional allocation was derived. This allocation was based on the same methodology KU and LG&E have historically used in their base rate cases, and is unchanged from their last rate cases, Case No. 2018-00294 and Case No. 2018-00295.

The effective tax rate, computed as "Total Income Taxes" per row 111 for KU, row 105 for LG&E Electric, and row 89 for LG&E Gas, divided by "Book Net Income before Income Tax & Credits" per row 3, is 20.1 percent for the base period and 13.6 percent for the pro forma forecasted test period for KU, 18.3 percent for the base period and 7.3 percent for the pro forma forecasted test period for LG&E Electric, and 21.8 percent for the base period and 21.3 percent for the pro forma forecasted test period for LG&E Gas.

XIII. GROSS REVENUE CONVERSION FACTOR

Q. Have the Companies each prepared a computation of a gross revenue conversion factor for the forecasted test period as required by 807 KAR 5:001 Section 16(8)(h)?

A. Yes. This information ("Schedule H") is located at Tab 61 to each application. LG&E has prepared separate Schedule Hs for its electric and gas operations.

Q. Please describe Schedule H.

A. Each Schedule H sets forth the calculation of the gross revenue conversion factor ("GRCF"). This is the factor, or multiplier, used to gross-up the operating income deficiency to a revenue deficiency amount. The use of a GRCF is a long-standing practice in calculating the revenue requirement. This factor is designed to cover income taxes, uncollectible accounts expense, and revenue-based fees assessed by the Commission on the requested revenue increase. The federal and state income tax rates are calculated as shown in the attached Workpaper WPH-1 at Tab 61. The uncollectible accounts expense rate of 0.293% percent for KU and 0.203% for LG&E is based on the historic 5-year average. The rate used for the Commission assessment fee is based on the last assessment notice received by the Companies. The GRCF is used to compute the respective calculated revenue deficiency based on the associated calculated net operating income deficiency.

XIV. OTHER REGULATORY ASSETS AND LIABILITIES

Q. Are the Companies proposing modifications or updates to regulatory assets or regulatory liabilities in this case?

A. Yes, the Companies are proposing modifications to their deferral accounting practices associated with scheduled outages. In addition, LG&E is requesting amortization of its most recently approved storm-related regulatory asset over a ten-year period beginning when new rates take effect from this proceeding.

Updated Period for Scheduled Outages

Q. Please describe the generator outage expenses that are included in the Companies' revenue requirements.

A. As discussed in the testimony of Lonnie E. Bellar, the Companies propose the use of an eight-year average of generator outage expenses in their revenue requirements consistent with the ratemaking treatment from their 2016 base rate cases.[16] Historical expenses for January 2017 through August 2020 and forecasted expenses for September 2020 through 2024 were utilized to develop the eight-year average outage expense included in the forecasted test year. Additionally, the Companies have included amortization expense for the regulatory assets that have resulted from the

[16] Case Nos. 2016-00370 and 2016-00371, Stipulation and Recommendation, Article II, Section 2.2(F) (Ky. PSC Apr. 19, 2017).

2016 and 2018 rate cases in the forecasted test year. The regulatory asset balances are discussed below.

Q. Is this methodology different than what has been used by the Companies in the past?

A. Yes, this is a departure from the Stipulation and Recommendation reached in the 2018 rate case whereby a historic five-year average methodology was approved by the Commission. The Companies have not chosen to remain with this approach in the proposal put forth in this proceeding as the use of a historical five-year average results in a significant under collection of actual costs on an annual basis as evidenced by the large regulatory asset balances. The Companies proposal instead utilizes the eight-year average methodology contained in the Companies' 2016 Stipulation and Recommendation[17] and approved by the Commission.[18] The 2016 methodology allows the Companies to use regulatory asset and liability accounting for generator outage expenses that are greater or less than the eight-year average of the Companies' generator outage expenses. Both the 2016 and 2018 methodologies ensure the Companies ultimately may collect, or will have to return to customers, through future base rates any amounts that are above or below the average embedded in the electric revenue requirement increases in these proceedings.[19]

Q. Do the Companies currently have regulatory assets or liabilities associated with the generator outages from their last base rate cases?

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[17] *Id.*

[18] Case No. 2016-00370, Order (Ky. PSC June 22, 2017); Case No. 2016-00371, Order (Ky. PSC June 22, 2017).

[19] Case No. 2016-00370 and Case No. 2016-00371, Stipulation and Recommendation, Article II, Section 2.2(F) (Ky. PSC Apr. 19, 2017).

A. Yes. As of June 30, 2021, KU forecasts a $37.6 million jurisdictional regulatory asset associated with generator outage expense from the 2018 base rate case. As of June 30, 2021, LG&E forecasts a $11.1 million regulatory asset associated with the scheduled outages from the 2018 base rate case. The Companies are proposing to amortize these amounts over an eight-year period consistent with the 2018 base rate case with amortization beginning when new base rates take effect.

As of June 30, 2021, KU forecasts a $2.6 million remaining jurisdictional regulatory asset associated with generator outage expense from the 2016 base rate case. As of June 30, 2021, LG&E forecasts a $6.4 million regulatory asset associated with the scheduled outages from the 2016 base rate case. The Companies are proposing to amortize these remaining balances over a six-year period (eight-year amortization period less 2 years of amortization resulting from the 2018 rate case) when new base rates take effect.

LG&E-Storm Regulatory Asset

Q. Describe LG&E's requested regulatory asset treatment in Case No. 2019-00017 relating to the storms that occurred in November 2018.

A. On November 14, 2018, a mix of snow, ice, and freezing rain caused widespread power outages across LG&E's service territory and approximately $6.8 million in incremental operations and maintenance costs.[20] Pursuant to Commission order, LG&E notified the Commission of the establishment of a deferred asset as of December 31, 2018 within the required five day period for storms occurring in the fourth quarter.[21] LG&E

[20] *Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset*, Case No. 2019-00017, Application (Ky. PSC Jan. 11, 2019).
[21] Case No. 2019-00017, Application at 6-7 (Ky. PSC Jan. 11, 2019).

asked the Commission to authorize and confirm LG&E's establishment of its regulatory asset to defer for future recovery its actual, incremental November 2018 Ice Storm-related operations and maintenance costs.[22] The Commission approved LG&E's request and ordered that the amount of the regulatory asset to be amortized and included in rates should be determined in LG&E's next rate case.[23]

Q. What is LG&E requesting in this case?

A. The current balance of the November 2018 Ice Storm regulatory asset is $6.5 million. LG&E is requesting these costs be amortized over a ten-year period beginning when new rates take effect from this proceeding. The ten-year amortization period is consistent with the most recent case involving significant storm damages.[24]

XV. DEPRECIATION RATES

Q. Have the Companies completed new depreciation studies?

A. Yes, they have. KU and LG&E engaged Mr. John Spanos of Gannett Fleming, Inc. to perform depreciation studies on all rates.

Q. Why did the Companies decide to file new depreciation studies?

A. The Companies are filing new depreciation studies for several reasons. First and most importantly, the Companies analyzed the retirement dates of their generation units referenced in the existing depreciation rates based on the changes in economic or environmental regulations. The analysis, discussed in Mr. Bellar's testimony and presented in Exhibit LEB-2, shows many of the current retirement dates are no longer reasonable, and determines new retirement dates. Secondly, as noted by Mr. Spanos,

[22] Case No. 2019-00017, Application (Ky. PSC Jan. 11, 2019).
[23] Case No. 2019-00017, Order at 4 (Ky. PSC Mar. 25, 2019).
[24] Case No. 2018-00304, Order at 5 (Ky. PSC Dec. 20, 2018); *see also* Case No. 2018-00294, Order at 9, 30 (Ky. PSC Apr. 30, 2019) and Case No. 2018-00295, Order at 10, 33 (Ky. PSC Apr. 30, 2019).

it has become common practice in the industry to update depreciation rates on a more frequent basis due to industry changes, especially the impact of ever-increasing environmental regulations or fuel alternatives to coal for steam generation assets. A new study is needed to ensure depreciation rates remain appropriate.[25] Outdated rates can create intergenerational inequities among customers and create stranded assets. Finally, to keep depreciation rates current, the Commission recommends new depreciation studies to be performed approximately every five years.[26] In a letter dated July 12, 2017 from the Virginia State Corporation Commission Staff, KU is directed to file its next depreciation study on or before December 31, 2020 for its operations in Virginia. Nearly five years have passed since the last study on all rates. For these reasons, the Companies determined that 2020 was the appropriate time to conduct a new depreciation study on all rates.

Q. Why did KU and LG&E choose Mr. Spanos of Gannett Fleming, Inc. to update its depreciation rates?

A. Mr. Spanos has extensive experience in the regulated utility accounting field, and particularly in the area of depreciation rates. Mr. Spanos is a member of the Society of Depreciation Professionals and has submitted testimony to over twenty-five regulatory commissions on the subject of utility plant depreciation. He has previously prepared

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[25] The last depreciation study analyzing all rates was in December 2015. It was used in the Companies' 2016 rate case proceedings. See Case No. 2016-00370 and Case No. 2016-00371, Direct Testimony of John J. Spanos (Ky. PSC Nov. 23, 2016).

[26] *See, e.g.*, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications*, Case No. 2017-00349, Order (Ky. PSC May 3, 2018); *Application of Nolin Rural Electric Cooperative Corporation for a General Rate Increase*, Case No. 2016-00367, Order (Ky. PSC June 21, 2017); *Application of Kenergy Corp. for a General Adjustment in Rates*, Case No. 2015-00312, Order (Ky. PSC Sept. 15, 2016); *Adjustment of Rates of Fleming-Mason Energy Cooperative Corporation*, Case No. 2001-00244 (Ky. PSC Aug. 7, 2002).

depreciation studies for KU and LG&E that were presented to the Commission in numerous cases for more than ten years.[27]

Q. What did KU and LG&E ask Mr. Spanos to do?

A. The Companies asked Mr. Spanos to perform an independent depreciation study, using data from historical records of KU and LG&E's plant, his generation asset life assessment analysis of the Companies' assets, and his extensive experience in depreciation studies. The purpose of the depreciation studies was to evaluate the Companies' depreciation rates and, if necessary, recommend updated depreciation rates for the Companies' assets.

Q. What did Mr. Spanos find and recommend?

A. As in the case of many depreciation studies, Mr. Spanos found KU's and LG&E's current depreciation rates need to be updated to fully reflect the current or actual depreciation of the Companies' assets. Mr. Spanos recommended the Companies continue to use the Average Service Life ("ASL") and remaining life basis methodology of depreciation, consistent with the method and resulting rates the Commission accepted in the settlement of Case Nos. 2007-00565, 2008-00251, 2012-00221, 2012-00222, 2016-00370, and 2016-00371. The study resulted in revised life

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[27]Case No. 2018-00294 (Ky. PSC Sept. 28, 2018); Case No. 2018-00295 (Ky. PSC Sept. 28, 2018); Case No. 2016-00370 (Ky. PSC Nov. 23, 2016); Case No. 2016-00371 (Ky. PSC Nov. 23, 2016); *Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Depreciation Rates For Brown Solar*, Case No. 2016-00063 (Ky. PSC Jan. 29, 2016); *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2014-00371 (Ky. PSC Nov. 26, 2014); *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*, Case No. 2014-00372 (Ky. PSC Nov. 26, 2014); *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Case No. 2012-00221 (Ky. PSC June 29, 2012); *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, a Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222 (Ky. PSC June 29, 2012); *Application of Kentucky Utilities Company to File Depreciation Study*, Case No. 2007-00565 (Ky. PSC Dec. 28, 2007); *Application of Louisville Gas and Electric Company to File Depreciation Study*, Case No. 2007-00564 (Ky. PSC Dec. 28, 2007).

and salvage parameters based on updated historical information and industry benchmarks.

Q. Did KU and LG&E accept Mr. Spanos' recommendation to use the ASL methodology in its new depreciation studies?

A. Yes. The Companies accepted Mr. Spanos' recommendation to continue to use the ASL and remaining life basis methodology because it reasonably allocates depreciation over the remaining useful lives of the Companies' assets. The Companies also decided to use historical capital instead of forecasted capital when calculating depreciation rates because historical capital resulted in lower depreciation rates.

Q. Are KU and LG&E proposing increases to all rate classes based on Mr. Spanos' studies?

A. No. The Companies are not proposing increases to the electric distribution, electric transmission, gas distribution, or common/general plant rate classes.

Q. Did the depreciation studies consider the Companies' proposed modifications to the retirement dates of certain steam generating units?

A. Yes. As discussed in Mr. Bellar's Direct Testimony, the Companies conducted a study to examine the existing retirement dates for certain coal-fired generating units as reflected in existing depreciation rates based on maintaining system reliability to determine whether they were reasonable based on the changes in operational and economic circumstances and, if not, to determine reasonable retirement years. Mr. Spanos advised that these new retirement dates are reasonable and consistent with other retirement dates used by other companies based on the national practice.

XVI. <u>CONCLUSION</u>

Q. Do you have any recommendations for the Commission?

A. Yes. I recommend that the Commission: (1) approve the Companies' requested rates; (2) authorize the Companies to establish regulatory assets and liabilities and amortize the regulatory assets and liabilities as requested; and (3) accept and approve the depreciation rates set forth in Mr. Spanos' depreciation studies for only the Companies' generation assets.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Controller 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 foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

DocuSigned by:
Christopher M. Garrett
5B353C8395DE4D7...
Christopher M. Garrett

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

Judy Schooler
Notary Public

Notary Public, ID No. 603967

My Commission Expires:

July 11, 2022

APPENDIX A – PROFESSIONAL HISTORY / BACKGROUND

Christopher M. Garrett
Controller
Louisville Gas and Electric Company
Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3328

<u>Previous Positions:</u>

Director, Rates	Feb 2016 – Dec 2017
Director, Accounting and Regulatory Reporting	Dec 2012 – Jan 2016
Director, Financial Planning & Controlling	Feb 2010 – Nov 2012
Manager, Financial Planning	Nov 2007 – Feb 2010
Manager, Corporate Accounting	Jan 2006 – Oct 2007
Manager, Utility Tax	May 2002 – Jan 2006
Tax Analyst, various positions	Aug 1995 – May 2002

<u>Education:</u>

Eastern Kentucky University, Bachelor of Business Administration - Accounting, 1995
Graduated Magna Cum Laude
Certified Public Accountant, Kentucky, 1999

<u>Professional Memberships:</u>

American Institute of Certified Public Accountants (AICPA)
Kentucky Society of Certified Public Accountants (KYCPA)
Edison Electric Institute

<u>Civic Activities:</u>

The Louisville Free Public Library Foundation – Treasurer, Chair of Finance & Audit Committee and member of Executive Committee

APPENDIX B – RATE SCHEDULE A

Schedule A

To prepare the jurisdictional financial summary shown in Schedule A, each of the Companies first determined the amount of required operating income. For KU's required operating income, KU multiplied the required rate of return by the total capital allocated to KU's jurisdictional operations for the forecasted test period. For LG&E's required operating income for electric operations, LG&E multiplied the required rate of return by the total capital allocated to LG&E's electric operations for the forecasted test period. LG&E performed the same calculation for its gas operations. The total allocated capital and required rate of return are obtained from the cost of capital summary required by 807 KAR 5:001 Section 16(8)(j) ("Schedule J"). Total adjusted operating income produced by each company's present rates, which is found in the jurisdictional operating income summary required by 807 KAR 5:001 Section 16(8)(c) ("Schedule C"), is then subtracted from the total required operating income. The difference is then multiplied by the gross revenue conversion factor, whose computation is required by 807 KAR 5:001 Section 16(8)(h) ("Schedule H"), which takes into account the effects of various state and federal income taxes, Commission assessment fees, and bad debt expense. This product represents the additional revenues that each company's operations require to meet each company's reasonable operating expenses and earn a reasonable rate of return.

APPENDIX C – RATE SCHEDULE B

Schedule B

Schedule B consists of a summary schedule, Schedule B-1, showing each company’s calculated rate base for the base period and the forecasted test period. The information contained in Schedule B-1 derives from the remaining schedules in Schedule B, which calculate the rate base components and adjustments: Plant in Service (Schedules B-2 – B-2.7), Accumulated Depreciation and Amortization (Schedules B-3 – B-3.2), Construction Work in Progress (Schedule B-4 – B-4.2), Allowance for Working Capital (Schedules B-5 – B-5.2), Deferred Credits and Accumulated Deferred Income Taxes (Schedule B-6), and Jurisdictional Percentages (Schedules B-7 – B-7.2). Schedule B-8 provides comparative balance sheets for calendar years 2015-2019, as well as for the base period and for a 13-month average for the forecasted test period.

APPENDIX D – ARO ASSETS

KU and LG&E are proposing to remove ARO assets from their rate base consistent with their approach in previous cases.

In Case Nos. 2003-00426[28] and 2003-00427,[29] the Commission approved a stipulation that requested the Commission's approval for the following:

1) Approving the regulatory assets and liabilities associated with adopting SFAS No. 143 and going forward;[30]
2) Eliminating the impact on net operating income in the 2003 ESM annual filing caused by adopting SFAS No. 143;
3) To the extent accumulated depreciation related to the cost of removal is recorded in regulatory assets or regulatory liabilities, reclassifying such amounts to accumulated depreciation for rate-making purposes of calculating rate base; and
4) Excluding from rate base the ARO assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143.

In Case Nos. 2003-00433[31] and 2003-00434,[32] the Commission approved KU's and LG&E's proposed exclusion[33] of ARO assets from rate base. It again approved the exclusion in Case Nos. 2009-00548[34] and 2009-00549.[35] KU similarly excluded such amounts in Case Nos.

[28] *Application of Louisville Gas and Electric Company For An Order Approving An Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003*, Case No. 2003-00426, Order at 3 (Ky. PSC Dec. 23, 2003).
[29] *Application of Kentucky Utilities Company For An Order Approving An Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003*, Case No. 2003-00427, Order at 3 (Ky. PSC Dec. 23, 2003).
[30] The Financial Accounting Standards Board, which promulgates the U.S. Generally Accepted Accounting Principles, has renamed SFAS No. 143; it is now Accounting Standards Codification ("ASC") 410-20.
[31] *An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 21 (Ky. PSC June 30, 2004).
[32] *An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 20-22 (Ky. PSC June 30, 2004).
[33] Case No. 2003-00433, LG&E Response to Commission Staff's Third Set of Data Requests, No. 39 (Ky. PSC Mar. 11, 2004); Case No. 2003-00434, KU Response to Commission Staff's Third Set of Data Requests, No. 39 (Ky. PSC Mar. 11, 2004).
[34] *Application of Kentucky Utilities Company For An Adjustment of Base Rates*, Case No. 2009-00548 (Ky. PSC July 30, 2010).
[35] *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549 (Ky. PSC July 30, 2010).

2016-00370,[36] 2014-00371,[37] 2012-00221[38] and 2008-00251,[39] which were resolved by Commission-approved settlements. LG&E similarly excluded such amounts in Case Nos. 2016-00371,[40] 2014-00372,[41] 2012-00222[42] and 2008-00252,[43] which were resolved by settlements approved by the Commission.[44]

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[36] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00370 (Ky. PSC June 22, 2017).
[37] *Application of Kentucky Utilities Company For An Adjustment Its Electric Rates*, Case No. 2014-00371 (Ky. PSC June 30, 2015).
[38] *Application of Kentucky Utilities Company For An Adjustment of Its Electric Rates*, Case No. 2012-00221 (Ky. PSC Dec 20, 2012).
[39] *Application of Kentucky Utilities Company For An Adjustment of Electric Base Rates*, Case No. 2008-00251 (Ky. PSC Feb. 5, 2009).
[40] *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Certificates of Public Convenience and Necessity*, Case No. 2016-00371 (Ky. PSC June 22, 2017).
[41] *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2014-00372 (Ky. PSC June 30, 2015).
[42] *Application of Louisville Gas and Electric Company For An Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and A Gas Line Surcharge*, Case No. 2012-00222 (Ky. PSC Dec 20, 2012).
[43] *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2008-00252 (Ky. PSC Feb. 5, 2009).
[44] CCR closure costs were approved for recovery through the ECR mechanism in Case Nos. 2016-00026 and 2016-00027.

APPENDIX E – RATE SCHEDULE C

Schedule C-1

Each Schedule C-1 summarizes KU's, LG&E Electric's, and LG&E Gas's jurisdictional operating revenues and expenses for each utility's operations for the base and forecasted test periods. The schedule depicts the base period level (Column 1), forecasted test period level at current rates (Column 3), and forecasted test period levels at the proposed rates (Column 5).

The amounts set forth in each Schedule C-1, Column 1 reflect that utility's adjusted base period amounts.[45] These amounts represent base year totals adjusted to remove revenues and expenses associated with the mechanisms and surcredits as these represent revenues and costs recovered outside of base rates. In addition, an interest synchronization adjustment is made to remove the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through the rate mechanisms. The removal of these revenues and expenses is shown on Schedule D-2.

The adjustments in Schedule C-1, Column 2 are detailed in Schedule D-1.

Schedule C-1, Column 4 reflects the change in revenues and expenses resulting from the implementation of the proposed rates. The increases in expenses reflect the changes in income taxes, bad debt expenses (included in "Operation and Maintenance Expenses"), and Commission assessment fees (included in "Taxes Other Than Income") related to the increased revenues.

Schedule C-2

For KU and LG&E Electric, Schedule C-2 details each utility's adjusted jurisdictional operating income statement for the base period and the forecasted test period as used in Columns 1 and 3 of Schedule C-1, and breaks down "Forecasted Adjustments at Current Rates" per Column 2 of Schedule C-1 between "Jurisdictional Adjustments to Base Period" (Column 2 of Schedule C-2) and "Jurisdictional Pro-Forma Adjustments to Forecasted Period" (Column 4 of Schedule C-2).

Schedule C-2, Column 2 represents adjustments to the base period amounts to reflect forecasted test period conditions. These adjustments are shown in detail on Schedule D-1, Column 2 and are described at Schedule D-1, Column 6.

Schedule C-2, Column 4 reflects the pro forma adjustments to forecasted test period operations. These adjustments are listed in detail in Schedule D-2.1. The amounts in Schedule C-2, Column 4 correspond to the amounts in the column labeled "Jurisdictional Pro Forma Adjustments to Forecast Period" on Schedule D-2.1.

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[45] These amounts are shown at pages 1 – 6 of Schedule C-2.1, Column 5 for KU and LG&E Electric. This amount is shown at pages 1 – 5 of Schedule C-2.1, Column 5 for LG&E Gas.

Schedule C-2, Column 5 represents the pro forma forecasted test period amount. The amounts in Column 5 correspond to those in Schedule C-1, Column 3.

Schedule C-2.1

Schedule C-2.1 is a statement of jurisdictional operating revenues and expenses by account for the base period and for the forecasted test period. It details how each utility's jurisdictional net operating income was determined for the base period and forecasted test period.

Schedule C-2.2

Schedule C-2.2 is a comparison of each utility's operations on a monthly basis for the base period and for the forecasted test period. The information in this schedule is further classified by account. The information for the six months ending August 31, 2020 reflects actual results. The remaining months of the base period and all of the forecasted test period are forecasted.

APPENDIX F – RATE SCHEDULE D

Schedule D

Each Schedule D is comprised of three schedules. Schedule D-1 shows operating revenue and expenses by account, for both the base period and the forecasted test period and the level of variance between the two. Certain jurisdictional pro forma adjustments are then applied to the forecasted test period to derive the pro forma forecasted test period used in Schedule C.

Schedule D-2 provides the adjustments for both the base period and the forecasted test period to operating revenues and expenses by FERC account necessary to remove the effects of each utility's other recovery mechanisms and surcredits. In addition, an interest synchronization adjustment is made to remove the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through the rate mechanisms. The amounts shown in the "Jurisdictional Adjustments" column appear in Column 4 of Schedule C-2.1 in the column "Jurisdictional Adjustments Sch D-2."

Schedule D-2.1 provides the pro forma adjustments to operating revenues and expenses by FERC account each utility is proposing in these proceedings for the forecasted test period. The amounts shown in the "Jurisdictional Pro Forma Adjustments to Forecast Period"[46] column appear in Column 4 of Schedule D-1 in the column "Jurisdictional Pro Forma Adjustments to Forecasted Period."

[46] For LG&E Gas, this column is titled "Jurisdictional Adjustments."

APPENDIX G – ELECTRIC AND GAS PRO FORMA ADJUSTMENTS

Electric Pro Forma Adjustments (both KU and LG&E)

DSM Adjustments

LG&E and KU are proposing adjustments to operating revenues and expenses as shown in Schedule D-2 that eliminate revenues recovered through the DSM mechanism and related expenses. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, an adjustment was made to eliminate electric revenues to be recovered through the DSM mechanism and the corresponding expenses for both the base period and the forecasted test period.[47] The operating revenue and expense components of the adjustment are shown in the column labeled "Adj. 1 Remove DSM Mechanism" of Schedule D-2. The supporting details are contained in Schedule WPD-2.

The adjustments shown in Schedule J-1.1/1.2 and Supporting Schedule B-1.1 remove DSM rate base from KU's and LG&E's rate base and capitalization, respectively. In accordance with the Commission's Orders in Case No. 2011-00134 and Case No. 2014-00003, the Companies capitalize the cost of installing load-control switches and related equipment used in two of its DSM programs, the Residential Load Management/Demand Conservation Program and the Commercial Load Management/Demand Conservation Program.[48] In accordance with the Commission's Order in Case No. 2014-00003, the Companies have previously capitalized the cost of advanced meters, related communications equipment, and other related capital items.[49] Because the Companies recover the cost of those investments, as well as a return on those investments, through the DSM mechanism, Column 4 of Supporting Schedule B-

[47] The Commission has previously reviewed and accepted adjustments for KU similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 22 (Ky. PSC June 30, 2004); *Application of Kentucky Utilities Company For An Adjustment of Base Rates*, Case No. 2009-00548, Order at 18 (Ky. PSC July 30, 2010). In Case Nos. 2008-00251, 2012-00221, 2014-00371, 2016-00370, and 2018-00294 base rate cases that were resolved by Commission–approved settlement agreements, KU also proposed similar adjustments. The Commission has also previously reviewed and accepted adjustments for LG&E similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 24-25 (Ky. PSC June 30, 2004); *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 19-20 (Ky. PSC July 30, 2010). In Case Nos. 2008-00252, 2012-00222, 2014-00372, 2016-00371, and 2018-00295 base rate cases that were resolved by Commission-approved settlement agreements, LG&E also proposed similar adjustments.

[48] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs*, Case No. 2011-00134, Order at 14 (Ky. PSC Nov. 9, 2011) ("The Companies' request to add a fifth element to the DSMRC to account for the capital expenditure needed to develop the Residential and Commercial Load Management/Demand Conservation Program in the DSM/EE Program Plan is granted."); *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy Efficiency Programs*, Case No. 2014-00003, Order (Ky. PSC Nov. 14, 2014).

[49] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy Efficiency Programs*, Case No. 2014-00003, Order (Ky. PSC Nov. 14, 2014).

1.1 removes DSM rate base from each company's rate base and Column H for KU and Column F for LG&E Electric of page 1 of Schedule J-1.1/1.2 removes DSM rate base and other mechanism-related rate base from each company's capitalization. These adjustments were performed using a methodology similar to that used in the Companies' four most recent base rate cases, all of which were resolved by Commission-approved settlement agreements.

ECR Adjustments

<u>Eliminate ECR Revenues and Expenses:</u>
Schedule D-2 also shows the Companies' proposed adjustment to operating expenses and revenues to eliminate ECR revenues and expenses. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, an adjustment was made to eliminate ECR revenues and expenses during the forecasted test period that will continue to be included through the ECR mechanism after the implementation of new base rates. The operating revenue and expense components of the adjustment for both the base period and the forecasted test period are shown in the column labeled "Adj. 2 Remove ECR Mechanism" of Schedule D-2. The supporting details are contained in Schedule WPD-2. The ECR surcharge is provided for full recovery of approved environmental costs that qualify for the surcharge.

Consistent with the Commission's Orders in Case Nos. 2009-00310 and 2009-00311 approving the use of the revenue requirement method for calculating the monthly ECR billing factor, the Companies are removing all ECR revenues collected in the environmental surcharge and in base rates.[50] The removal of ECR revenues from base rates is necessary to ensure base revenues reflect only base rate components and costs are recovered through the appropriate rate-making mechanism. KU proposed such an adjustment using this methodology in Case Nos. 2012-00221, 2014-00371, 2016-00370, and 2018-00294, all of which were resolved by Commission-approved settlement agreements. LG&E proposed such an adjustment using this methodology in Case Nos. 2012-00222, 2014-00372, 2016-00371, and 2018-00295, all of which were resolved by Commission-approved settlement agreements.

The Companies are proposing adjustments to remove ECR rate base from their rate base and capitalization in Schedule J-1.1/1.2 and Supporting Schedule B-1.1, respectively. Removing KU's and LG&E's ECR rate base from their capitalization and rate base is necessary because each company is recovering its investment, as well as a return on its investment, through the ECR mechanism. Column 3 of Supporting Schedule B-1.1 removes ECR rate base from KU's and LG&E's rate base and Column H for KU and Column F for LG&E Electric of page 1 of Schedule J-1.1/1.2 removes

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[50] *An Examination By The Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Electric Company for the Two-Year Billing Period Ending April 30, 2009*, Case No. 2009-00310, Order (Ky. PSC Dec. 2, 2009); *An Examination By The Public Service Commission of the Environmental Surcharge Mechanism of Louisville Gas and Electric Company for the Two-Year Billing Period Ending April 30, 2009,* Case No. 2009-00311, Order (Ky. PSC Dec. 2, 2009).

ECR rate base and other mechanism-related rate base from KU's and LG&E's capitalization.

KU performed these adjustments using a methodology the Commission approved in Case Nos. 2009-00548 and 2003-00434 and that KU also proposed in Case Nos. 2018-00294, 2016-00370, 2014-00371, 2012-00221, and 2008-00251, which were resolved by Commission-approved settlement agreements.

LG&E performed these adjustments using the methodology that the Commission approved in Case Nos. 2009-00549, 2003-00433, 98-426[51] and that LG&E also proposed in Case Nos. 2016-00371, 2014-00372, 2012-00222, and 2008-00252, which were resolved by settlement agreements.

<u>ECR for Off-System Sales:</u>
In determining the monthly ECR surcharge, a portion of KU's and LG&E's environmental compliance costs are allocated to OSS, including intercompany sales, through the jurisdictional allocation ratio. Because total ECR expenses are removed through the adjustment in Schedule D-2, the expenses associated with off-system and intercompany sales are understated. This results in a mismatch of the revenues and expenses related to the off-system and intercompany sales portion of the allocated environmental surcharge monthly revenue requirement. The Companies have included in this adjustment a reduction to electric revenues associated with ECR-related off-system and intercompany sales revenues. The electric operating revenue components of this adjustment are shown in the column labeled "Adj 7 ECR for Off-System Sales" of Schedule D-2.1. The supporting details are contained in Schedule WPD-2.1. KU and LG&E performed the adjustments in a manner consistent with the methodology used in their last rate cases Case Nos. 2018-00294 and 2018-00295.

FAC Adjustment

Schedule D-2 shows the adjustment to operating expenses and revenues to eliminate the FAC revenues. Consistent with past Commission practice in KU's and LG&E's prior base rate cases, this adjustment eliminates the difference between fuel expenses and base fuel revenues. The operating revenue and expense components of the adjustment for both the base period and the forecasted test period are shown in the column labeled "Adj 3 Remove FAC Mechanism" of Schedule D-2. The supporting details are contained in Schedule WPD-2.[52]

[51] *Application of Louisville Gas and Electric Company for Approval of an Alternate Method of Regulation of Its Rates and Service*, Case No. 98-426, Order (Ky. PSC June 1, 2000).

[52] The Commission has previously reviewed and accepted adjustments for KU similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 22 (Ky. PSC June 30, 2004); *Application of Kentucky Utilities Company For An Adjustment of Base Rates*, Case No. 2009-00548, Order at 18 (Ky. PSC July 30, 2010). In Case Nos. 2008-00251, 2012-00221, 2014-00371, 2016-00370, and 2018-00294 base rate cases that were resolved by Commission–approved settlement agreements, KU also proposed similar adjustments. The Commission has previously reviewed and accepted adjustments for LG&E similar to the proposed adjustment. *See An Adjustment of the Electric Rates,*

OSS Adjustment

The Companies are proposing an adjustment to operating expenses and revenues to eliminate OSS revenues, OSS mechanism revenues, and OSS expenses shown in Schedule D-2. In Case Nos. 2014-00371 and 2014-00372, the Commission ordered that an OSS adjustment clause be implemented under which electric OSS margins would be shared on a 75 percent - 25 percent basis between customers and the Companies, respectively. The Commission further ordered that OSS margins attributable to customers (75 percent) be flowed through the FAC.

Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, an adjustment was made to eliminate OSS revenues, OSS mechanism revenues, and OSS expenses included in the forecasted test period. The operating revenue and expense component of the adjustment for the base period and the forecasted test period are shown in the column labeled "ADJ 4 Remove OSS Mechanism" of Schedule D-2. Supporting details are contained in WPD-2. OSS revenues and expenses will continue to be addressed through the OSS mechanism after the implementation of new base rates. This treatment is consistent with the Companies' treatment in their last base rate cases, Case Nos. 2018-00294 and 2018-00295.

Interest Synchronization Adjustment

The Companies are proposing "Adj 6 Interest Synchronization" shown on Schedule D-2. This adjustment is for federal and state income taxes corresponding to the adjustment of interest expense. The Commission has historically recognized the income tax effects of adjustments to interest expense through an "interest synchronization" adjustment. Income tax expense is adjusted to remove the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through the other rate mechanisms, predominantly the ECR surcharge. The interest expense on KU's and LG&E's "Jurisdictional Adjusted Capital" is computed using the rates from Schedule J-1.1/J-1.2 Column J and that amount is then compared to KU's and LG&E's interest per books (excluding other interest) to arrive at the interest synchronization amount. The composite federal and state income tax rate is then applied to the interest synchronization amount. The supporting details are contained in Schedule WPD-2. The Companies performed the adjustment consistent with the methodology used in their last base rate cases, Case Nos. 2018-00294, 2018-00295, 2016-00370, 2016-00371, 2014-00371, and 2014-00372.

Advertising Expense Adjustment

Terms and Conditions of Louisville Gas and Electric Company, Case No. 2003-00433, Order at 24-25 (Ky. PSC June 30, 2004); *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 19-20 (Ky. PSC July 30, 2010). In Case Nos. 2008-00252, 2012-00222, 2014-00372, 2016-00371, and 2018-00295 base rate cases that were resolved by Commission-approved settlement agreements, LG&E proposed a similar adjustment.

The Companies are proposing "Adj 8 Advertising Expenses" shown on Schedule D-2.1 to remove all promotional advertising expenses.[53] The supporting details are contained in Schedule WPD-2.1. The Companies performed the adjustment consistent with the methodology used in their last base rate cases, Case Nos. 2018-00294 and 2018-00295.

Gas Pro Forma Adjustments

DSM Adjustment

The adjustment to gas operating revenues and expenses shown in Schedule D-2 for gas operations eliminates revenues recovered through the DSM mechanism and related expenses. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers,[54] an adjustment was made to eliminate gas revenues to be recovered through the DSM mechanism and the corresponding expenses for both the base period and the forecasted test period. The gas operating revenue and expense components of the adjustment are shown in the column labeled "Adj. 1 Remove DSM Mechanism" of Schedule D-2 for gas operations. The supporting details are contained in Schedule WPD-2 for gas operations.

GLT Adjustments

LG&E is proposing an adjustment to gas operating revenues and expenses that eliminates GLT revenues and expenses, which is also shown on Schedule D-2. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, LG&E has eliminated revenues to be recovered through the GLT and the corresponding expenses for both the base period and the forecasted test period.[55] The gas operating revenue and expense components of the adjustment are shown in the column labeled "Adj. 2 Remove GLT Mechanism" of Schedule D-2 for gas operations. The supporting details are contained in Schedule WPD-2 for gas operations.

LG&E's proposed removal of GLT rate base from LG&E's gas rate base and capitalization is shown on Schedule J-1.1/1.2 for gas operations and Supporting Schedule B-1.1 for gas operations, respectively. Removing LG&E's GLT rate base from its gas capitalization and rate base is necessary because LG&E is recovering its

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[53] *See* 807 KAR 5:016, Section 1.

[54] The Commission has previously reviewed and accepted adjustments similar to the proposed adjustment. *See An Adjustment of the Electric Rates, Terms and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433, Order at 24-25 (Ky. PSC June 30, 2004); *Application of Louisville Gas and Electric Company For An Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549, Order at 19-20 (Ky. PSC July 30, 2010). In Case Nos. 2008-00252, 2012-00222, 2014-00372, and 2018-00295, base rate cases that were resolved by Commission-approved settlement agreements, LG&E also proposed a similar adjustment.

[55] This adjustment is similar to the DSM revenue and expense elimination adjustment that the Commission has previously found to be reasonable and that LG&E has proposed in its six most recent base rate cases. In Case No. 2018-00295, which was resolved by Commission-approved settlement agreement, LG&E proposed the same adjustment regarding GLT revenues and expenses as proposed in its current application.

investment, as well as a return on its investment, through the GLT mechanism. Therefore, Column 10 of Supporting Schedule B-1.1 for gas operations removes GLT rate base from LG&E's gas rate base, and Column F of page 2 of Schedule J-1.1/1.2 for gas operations removes GLT rate base and other mechanism-related rate base from LG&E's gas capitalization. Removing GLT rate base from LG&E's gas capitalization and rate base is consistent with the removal of DSM rate base, which I describe above, and with the adjustment that LG&E proposed in Case Nos. 2014-00372,[56] 2016-00371,[57] and 2018-00295.[58]

GSC Adjustment

LG&E is also proposing an adjustment shown on Schedule D-2 that eliminates GSC recoveries and expenses. Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-cost-recovery trackers, this adjustment eliminates the effect of GSC recoveries and gas supply expenses for both the base period and the forecasted test period. The gas operating revenue and expense components of the adjustment are shown in the column labeled "Adj. 3 Remove GSC Mechanism" of Schedule D-2 for gas operations. The supporting details are contained in Schedule WPD-2 for gas operations.

The Commission determined a similar adjustment to be reasonable in Case No. 2009-00549. LG&E proposed a similar adjustment in Case Nos. 2003-00433, 2008-00252, 2012-00222, 2014-00372, 2016-0037, and 2018-00295 which were resolved by Commission-approved settlement agreements.

Interest Synchronization Adjustment

LG&E's proposed adjustment labeled "Adj 5 Interest Synchronization" is included on Schedule D-2. This adjustment is for federal and state income taxes corresponding to the adjustment of interest expense. The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an "interest synchronization" adjustment. Income tax expense is adjusted to remove the tax benefit for the deduction of interest on debt capitalization associated with capital projects recovered through the other rate mechanisms, predominantly the GLT. The interest expense on LG&E's "Jurisdictional Adjusted Capital" is computed using the rates from Schedule J-1.1/J-1.2 Column J and that amount is then compared to LG&E's interest per books (excluding other interest) to arrive at the interest synchronization amount. The composite federal and state income tax rate is then applied to the interest synchronization amount. The supporting details are contained in Schedule WPD-2. LG&E performed the adjustment consistent with the methodology used in its last base rate case, Case No. 2018-00295.

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[56] *See* Case No. 2014-00372, Testimony of Robert M. Conroy at 16 (Ky. PSC Nov. 26, 2014).
[57] *See* Case No. 2016-00371, Testimony of Christopher M. Garrett at 36 (Ky. PSC Nov. 23, 2016).
[58] *See* Case No. 2018-00295, Testimony of Christopher M. Garrett at 31 (Ky. PSC Sept. 28, 2018).

Advertising Expense Adjustment

LG&E is proposing "Adj 7 Advertising Expenses" shown on Schedule D-2.1 to remove all promotional advertising expenses.[59] The supporting details are contained in Schedule WPD-2.1. The Companies performed the adjustment consistent with the methodology used in their last base rate cases, Case Nos. 2018-00294.

[59] *See* 807 KAR 5:016, Section 1.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00350**

TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

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I. BACKGROUND

Q. Please state your name, position, and business address.

A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes. I have testified in numerous proceedings before the Commission, including KU's and LG&E's 2018 base rate cases.[1]

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to: (1) support certain exhibits required by the Commission's regulations; (2) describe the methods by which the Companies informed their customers of the proposed rate adjustment; (3) explain how the Companies' proposed Advanced Metering Infrastructure ("AMI") deployment meets certificate of public convenience and necessity ("CPCN") requirements and will enable innovative rate options and support the requested regulatory deviations; (4) present the revenue

[1] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Rates*, Case No. 2018-00294, Testimony of Robert M. Conroy (Ky. PSC Sep. 28, 2018); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates,* Case No. 2018-00295, Testimony of Robert M. Conroy (Ky. PSC Sep. 28, 2018).

effects and bill impacts to the average residential customer; (5) present the Companies' recommendation for the allocation of the proposed increases in electric and gas revenues among the customer classes based on the results of the Companies' cost of service studies prepared by William Steven Seelye and The Prime Group in these cases; and (6) discuss and explain the various tariff changes the Companies propose.

II. FILING REQUIREMENTS

Q. Are you supporting certain information required by Commission regulation 807 KAR 5:001?

A. Yes, I am sponsoring the following schedules for the corresponding filing requirements for both Companies:

• Name, Address, Facts	Section 14(1)	Tab 1
• Corp. – Incorporation, Good Standing	Section 14(2)	Tab 1
• LLC – Organized, Good Standing	Section 14(3)	Tab 1
• LP – Agreement	Section 14(4)	Tab 1
• Reason for Rate Adjustment	Section 16(1)(b)(1)	Tab 2
• Certificate of Assumed Name	Section 16(1)(b)(2)	Tab 3
• Proposed Tariff	Section 16(1)(b)(3)	Tab 4
• Proposed Tariff Changes	Section 16(1)(b)(4)	Tab 5
• Statement about Customer Notice	Section 16(1)(b)(5)	Tab 6
• Notice of Intent	Section 16(2)	Tab 7
• Financial data for forecasted period presented as pro forma adjustments to base period	Section 16(6)(a)	Tab 8

• Forecasted adjustments limited to twelve (12) months immediately following suspension period	Section 16(6)(b)	Tab 9
• Capitalization and net investment rate base	Section 16(6)(c)	Tab 10
• No revisions to forecast	Section 16(6)(d)	Tab 11
• Commission may require alternative forecast	Section 16(6)(e)	Tab 12
• Testimony	Section 16(7)(a)	Tab 14
• Narrative description and explanation of all proposed tariff changes	Section 16(8)(l)	Tab 65
• Typical bill comparison under present and proposed rates for all customer classes	Section 16(8)(n)	Tab 67
• Customer Notice Information	Section 17	Tab 68

III. CUSTOMER NOTICE

Q. Please describe the methods by which the Companies informed their customers of their proposed electric and gas rate adjustments.

A. Notice to the public of the proposed rate adjustments is being given in accordance with the Commission's November 10, 2020 orders in these proceedings, which approved an alternative means of providing notice of these applications and the Companies' proposed rate adjustments. The Companies delivered notices of the filing of their applications, including their proposed rates, to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation through the Commonwealth of Kentucky in which customers affected reside, for publication in the applicable newspapers once a week for three consecutive weeks beginning November 18, 2020.

In addition to, and in accordance with, the requirements of the Commission's November 10, 2020 orders, the Companies took and are taking the following actions:

- Beginning November 18, the Companies posted at their offices and places of business a complete copy of the more detailed and lengthy notice that Section 17 requires and are maintaining these postings until completion of these rate case proceedings.

- Beginning November 18, the Companies posted on their website a copy of the more detailed and lengthy notice that Section 17 requires and a hyperlink to the location on the Commission's website where case documents and tariff filings are available.

- Beginning on November 30, the Companies will include a general statement explaining their application for rate adjustments with the bills of all of their Kentucky retail customers during the course of their regular billing cycle.

- On the same day the Companies are filing these applications they are notifying by electronic mail the chief executive officer or legal counsel of each entity that was granted intervention or otherwise permitted to participate in either or both of the Companies' most recent base-rate cases (Case Nos. 2018-00294 and 2018-00295) of the filing of these applications and are providing a hyperlink to the location on the Commission's website where case documents and tariff filings are available.

- On November 13, the Companies issued press advisories to all known news media organizations who cover the areas within their certified territory advising of the filing of their applications and including a hyperlink to the location on the Companies' and the Commission's websites where case documents and tariff filings will be available. The hyperlink to the Companies' website contained the same notice being published by the newspapers until November 25. On November 25, the Companies' website was updated to contain the complete public version of the applications filed with the Commission.

- Contemporaneously with the filing of these applications, the Companies are filing the customer notice as a separate document, labeled "Customer Notice of Rate Adjustment," to enable ratepayers checking the Commission's website to easily locate the notice.

Furthermore, KU is posting the notice to the public along with a complete copy of its application for public inspection at the KU business office located at One Quality Street, Lexington, Kentucky 40507. Similarly, LG&E is posting the notice to the public along with a complete copy of its application for public inspection at the LG&E business office located at 820 West Broadway, Louisville, Kentucky 40202.

Finally, the Companies are also posting a complete copy of each application in these cases on their website (www.lge-ku.com), along with a link to the Commission's website where the case documents are available.

IV. PROPOSED REVENUE INCREASES AND BILL IMPACTS

Q. Please briefly describe the revenue increases the Companies are requesting.

A. KU is requesting a 10.4 percent, or approximately $170.1 million, increase in its annual revenue. LG&E is requesting an 11.6 percent, or approximately $131.1 million, increase in its annual electric revenue, and an 8.3 percent, or approximately $30.0 million a year, increase in its annual gas revenue. Kent W. Blake describes in his testimony the primary drivers of the needed revenue increases.

As I discuss further below, the Companies are also requesting approval for an Economic Relief Surcredit Adjustment Clause ("Economic Relief Surcredit"), which will credit to customers a total of $53.5 million over twelve months when new rates go into effect from these proceedings. Of that $53.5 million, $11.9 million will go to KU customers, $38.9 million will go to LG&E electric customers, and $2.7 million will go to LG&E gas customers.

Q. If the Commission approves the proposed base rates and Economic Relief Surcredit, what will be the percentage increases in monthly residential electric and gas bills?

A. After taking into account the effect of the Economic Relief Surcredit, the average monthly KU residential bill increase for the first twelve months following the approval of new base rates will be 10.0 percent, or approximately $12.09, for a residential customer using an average of 1,120 kWh of electricity. When the surcredit expires, the average monthly KU residential bill increase will be 10.7 percent, or approximately $12.85, for a residential customer using the same amount electricity.

After taking into account the effect of the Economic Relief Surcredit, the average monthly LG&E residential electric bill increase for the first twelve months following the approval of new base rates will be 8.7 percent, or approximately $8.67, for a residential customer using an average of 894 kWh of electricity. When the surcredit expires, the average monthly LG&E residential electric bill increase will be 11.8 percent, or approximately $11.74, for a residential customer using the same amount of electricity.

After taking into account the effect of the Economic Relief Surcredit, the average monthly LG&E residential gas bill increase for the first twelve months following the approval of new base rates will be 8.9 percent, or approximately $5.83, for a residential customer using an average of 54 Ccf of gas. When the surcredit expires, the average monthly LG&E residential gas bill increase will be 9.4 percent, or approximately $6.17, for a residential customer using the same amount of gas.

Typical bill calculations for various levels of consumption are shown in Schedule N, which the Companies are providing to satisfy the filing requirement of Section 16(8)(n).

V. ECONOMIC RELIEF SURCREDIT ADJUSTMENT CLAUSE

Q. Please describe the Companies' proposed Economic Relief Surcredit Adjustment Clause (Sheet No. 89) that will apply to all three utilities (KU, LG&E electric, and LG&E gas).

A. As discussed in the testimony of Mr. Blake, the Companies have taken a series of specific steps and actions to mitigate the requested change in rates in these cases. One such step is the Companies' proposal to provide customers a one-year surcredit per kWh or Ccf through the Economic Relief Surcredit, which will provide a total surcredit of $53.5 million to customers across the Companies' three utility operations. The amount the surcredit will distribute to customers differs across the three utilities (KU $11.9 million, LG&E electric $38.9 million, and LG&E gas $2.7 million) due to the different items being included in the surcredit for each utility.

But the basic approach to the surcredit is the same for each utility: The total surcredit amount will be distributed on a per kWh or per Ccf basis over twelve months, with a one-month true-up charge or credit in the fifteenth month to ensure accurate distribution of the total surcredit amount per utility. The design of this surcredit is comparable to the surcredit approved by the Commission to distribute the benefits of the Tax Cuts and Jobs Act in Case No. 2018-00034.[2] Note that the items giving rise to the surcredit are removed from other rate case calculations in a manner consistent with other adjustment clauses.

Q. What is the amount of the proposed Economic Relief Surcredit that will be applied to customers' bills for all three utilities (KU, LG&E electric, and LG&E gas)?

A. The Companies have established a monthly credit, either per kWh or per Ccf, to be applied to customers' bills for twelve months beginning when base rates change in this proceeding. The table below shows the amount of the surcredit to be included in Sheet No. 89 for each utility:

[2] *Kentucky Industrial Utility Customers, Inc., Complainant, v. Kentucky Utilities Company and Louisville Gas and Electric Company, Defendants*, Case No. 2018-00034, Order (Ky. PSC Mar. 20, 2018).

	Economic Relief Surcredit
KU	$(0.00068) / kWh
LG&E Electric	$(0.00343) / kWh
LG&E Gas	$(0.00619) / Ccf

The amounts above will be applied to customers' bills beginning when base rates change in these proceedings and will continue for 12 consecutive months in accordance with the tariff.

Q. Please describe how the Economic Relief Surcredit was calculated.

A. Page 1 of Exhibits RMC-1, RMC-2, and RMC-3 to my testimony show the Economic Relief Surcredit calculations for KU, LG&E electric, and LG&E gas, respectively. The amount of the regulatory liability for each item included in the Economic Relief Surcredit is shown on Line 1. For the regulatory liability associated with the unprotected excess ADIT, the amount to be returned to customers is grossed up using the composite federal and state tax rate of 24.95% (Line 2). The total amount to be returned to customers through the Economic Relief Surcredit is shown on Line 3. Using the total billing units for the forecasted test year (Schedule M-2.2 for KU, Schedule M-2.2-E for LG&E electric, and Schedule M-2.2-G for LG&E gas) shown on Line 4, the surcredit per kWh or Ccf shown in the table above is calculated and shown on Line 5. For LG&E gas tariffs that are billed in Mcf (Rates AAGS, SGSS, FT, and LGDS), the surcredit per Mcf is also calculated and shown on Line 6 of Page 1 of Exhibit RMC-3 only.

Q. Please explain how the true-up will be calculated.

A. Following the completion of the one-year distribution under the Economic Relief Surcredit, the Companies will determine the amount of the true-up as the difference between the actual distribution and the amounts to be distributed noted above (KU \$11.9 million; LG&E electric \$38.9 million; and LG&E gas \$2.7 million). The true-up calculations for KU, LG&E electric, and LG&E gas are included on Page 2 of Exhibits RMC-1, RMC-2 and RMC-3, respectively. Once known, the actual amount returned to customers through the Economic Relief Surcredit will be input on Line 1. This amount will be subtracted from the amount forecasted to be returned to customers (Line 2 or Page 1, Line 3) with the result shown on Line 3. Using the applicable month's forecasted test year billing determinants in these proceedings as a proxy for the billing determinants for the fifteenth month following approval of the Economic Relief Surcredit (Line 4) (i.e., if September 2022 is the fifteenth month, the forecasted billing determinants for September 2021 in the test year will be used), the true-up charge or credit per kWh or Ccf will be calculated and shown on Line 5. For LG&E gas tariffs that are billed in Mcf (Rates AAGS, SGSS, FT, and LGDS), the Economic Relief Surcredit true-up charge or credit per Mcf will also be calculated and shown on Line 6 of Page 2 of Exhibit RMC-3 only.

Q. How do the Companies propose to provide the calculation of the true-up charge or credit per kWh or Ccf to the Commission for review?

A. Consistent with other adjustment clause filings, the Companies propose making a post-case filing in these proceedings ten days prior to the effective date of the true-up charge or credit. This filing will include updated Exhibits RMC-1, RMC-2, and RMC-3 with the only changes being to Page 2 to reflect the calculation of the true-up charge or credit.

Q. Please explain how the Economic Relief Surcredit true-up charge or credit will be applied to customers' bills once the one-year distribution period is complete.

A. The Economic Relief Surcredit true-up or charge will be applied as a one-time adjustment to bills rendered during the fifteenth billing period following approval of the Economic Relief Surcredit in these proceedings.

VI. ADVANCED METERING INFRASTRUCTURE DEPLOYMENT

Q. In these proceedings, the Companies are proposing to deploy AMI across their Kentucky service territories. How will deploying AMI affect the Companies' future tariff offerings?

A. The Companies are committing that, if the Commission approves the proposed AMI deployment, they will offer innovative rate designs to ensure customers receive benefits from AMI beyond the operational savings that will be reflected in their bills following future rate cases. For example, the Companies commit to offer a voluntary prepay option upon full deployment of AMI. In addition, the Companies commit to expand the availability of time-of-day rates after full AMI deployment. The Companies already have residential time-of-day rates (RTOD-Energy and RTOD-Demand) and are proposing in these proceedings two new General Time-of-Day rate schedules (GTOD-Energy and GTOD-Demand), all of which are optional rates with limited availability. The Companies will use their experience with these rate schedules and their Advanced Metering Systems Customer Service Offering ("AMS Offering"), as well as data from other utilities' AMI-driven tariff offerings, to create new rate schedules that will help customers maximize the benefits of AMI.

Q. Does the proposed AMI deployment meet Kentucky's CPCN requirements?

A. Yes, it fully satisfies Kentucky's CPCN requirements. To obtain a CPCN for an AMI deployment, the Commission has held that a utility must demonstrate need and lack of wasteful duplication.[3]

As the testimony of Lonnie E. Bellar, Eileen L. Saunders, and John K. Wolfe show, the Companies' proposed AMI deployment meets all the criteria for demonstrating need because it would enhance service, improve customers' control over their energy consumption, improve the reliability of its distribution system, create operational savings, and improve employee safety.

Mr. Bellar's testimony also shows that the Companies' proposed AMI deployment will produce net savings for customers over 30 years. These savings are hard, quantifiable operational savings, such as reduced meter-reading cost; they do not include benefits that, though real, are more difficult to quantify, such as enhanced theft protection. In addition, as discussed in the testimonies of Mr. Wolfe and Ms. Saunders, there are many qualitative benefits of having AMI deployed.

In addition, as Mr. Bellar's testimony shows, the Companies analyzed several alternatives to their proposed AMI deployment and determined that the proposed deployment is most beneficial for customers. This analysis is in addition to the Companies' more than 20 years of experience with advanced metering technology and investigation into the various AMI options currently available.[4] The Companies have

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[3] *See, e.g., Application of Duke Energy Kentucky, Inc. for (1) a Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief*, Case No. 2016-00152, Order at 9-10 (Ky. PSC May 25, 2017) (internal citations omitted).

[4] *See, e.g., Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for Full Deployment of Advanced Metering Systems*, Case No. 2018-00005, Direct Testimony of John P. Malloy Exh. JPM-1 at 8-10 (Ky. PSC Jan. 10, 2018).

therefore fully satisfied the requirement to conduct a thorough review of all reasonable alternatives to demonstrate a lack of wasteful duplication.[5]

Q. Will customers be able to opt out of the proposed AMI deployment?

A. Yes, customers will be able to opt out of the AMI deployment. I discuss the terms of the opt-out and the associated charges the Companies are proposing in the "Other Electric Rate and Tariff Changes" section of my testimony. In the same section, I also discuss AMI-related service disconnection and reconnection charges and policies.

Q. Are the Companies seeking any regulatory deviations related to the AMI deployment? If so, why should the Commission grant them?

A. Yes, the Companies are requesting the following regulatory deviations, which I believe the Commission should grant for the reasons stated below:

- 807 KAR 5:006, Section 7(5)(a) requires a utility to read each customer's meter at least quarterly except if prevented by reasons beyond its control and excepting customer-read meters subject to 807 KAR 5:006, Section 7(5)(b). In turn, 807 KAR 5:006, Section 7(5)(b) requires that a meter be read manually at least once during each calendar year. Commission Staff has previously opined that solid-state metering systems that record meter readings at least daily and transmit such meter readings directly to a utility's central office comply with this regulation without requiring a manual reading.[6] The Companies therefore request confirmation that LG&E will be in compliance with 807 KAR 5:006, Section 7(5)(a) and (b) if they do not physically read AMI meters. In the alternative, the Companies request a

[5] Case No. 2016-00152, Order at 11 (Ky. PSC May 25, 2017).
[6] Letter from Beth O'Donnell, Executive Director, Kentucky Public Service Commission, to Ron Sheets, President, Kentucky Association of Electrical Cooperatives (Sept. 27, 2006).

permanent deviation from this regulation because AMI metering equipment will transmit at least daily the same information to the Companies, eliminating the need to manually read the meters.

- 807 KAR 5:006, Section 14(3) requires the Companies to inspect the condition of meter and service connections before providing service to a new customer so that prior or fraudulent use of the facilities are not attributed to a new customer. The Companies are requesting a waiver for only AMI meters, which allow for remote data communication.[7] The Companies will continue to inspect the condition of legacy meters that have not yet been replaced.
- 807 KAR 5:006, Section 26 (4)(e) and 807 KAR 5:006, Section 26 (5)(a)(2) require the Companies to perform inspections on electric meters every two years and gas meters every three years. The annual cost to comply with these regulations is $300,000. AMI provides electronic information and alarms, including tampering alarms. Thus, the Companies will have notice if tampering occurs and can follow up with a physical inspection. Other information delivered from the meter provides the Companies details of the general condition of every meter in the system on a daily basis. Consequently, the intent of the two-year and three-year inspections may be met with the electronic information provided by the AMI and thus not require periodic physical inspections.
- 807 KAR 5:041, Section 16 and the Commission's final order in Case No. 2005-00276 require the Companies to perform sample and periodic meter testing

[7] The Commission granted a similar waiver to Duke Energy Kentucky in its AMI proceeding. *See* Case No. 2016-00152, Order at 16-17 (Ky. PSC May 25, 2017).

programs.[8] The Companies seek to suspend their existing sample program in the AMI deployment years and propose to resume the sample program post-AMI deployment. Continuing to randomly sample test meters would only add inefficiencies to the systematic geographical rollout of the AMI meter deployment. The Companies will return to testing sample meters after deployment is complete.

- 807 KAR 5:041, Section 15 (3) requires the Companies to test all removed meters. As reported quarterly to the Commission, the Companies have demonstrated that the vast majority of meters tested are operating accurately. Over the last five years, more than 99% of KU and LG&E electric meters tested have been within +/- 2%. Of the less than 1% of meters that are found to be fast or slow, 90% are slow and 10% are fast, meaning that only 0.06% of electric meters tested are fast.

  Testing costs to comply with this regulation are $3.3 million. This is a high cost to customers to identify roughly 0.06% of electric customers possibly impacted by a fast meter. The Companies seek to suspend their removal testing and propose to resume it post-AMI deployment. Additionally, the Companies request permission to dispose of removed meters immediately without testing them for accuracy because they will not be returned to service.

- 807 KAR 5:006, Section 19 states, "A utility shall make a test of a meter upon written request of a customer if the request is not made more frequently than once each twelve (12) months." On its face, this requirement would appear to apply only to meters still in service, not to meters already removed from service. But out of

[8] *The Joint Amended Application of the Utilities: Inter-County Energy Cooperative Corp., Kentucky Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Owen Electric Cooperative, Inc., and the Union Light, Heat, and Power Company for Approval of a Pilot Meter Testing Plan Pursuant to 807 KAR 5:041, Sections 13, 15, 16, 17, and 22*, Case No. 2005-00276, Order at 3 (Ky. PSC Nov. 10, 2005).

an abundance of caution, the Companies ask the Commission to grant a deviation from Section 19 regarding all meters the Companies remove as part of the AMI deployment. The reasons for the deviation are the same as those given above for the Companies' requested deviation from 807 KAR 5:041, Section 15(3) concerning testing of meters removed from service.

VII. ECR PROJECT ELIMINATION

Q. Do the Companies propose to eliminate certain Environmental Cost Recovery ("ECR") projects from their ECR mechanisms and monthly filings?

A. Yes, the Companies propose to eliminate KU Projects 28-31 and 34-38 (from KU's 2009, 2011, and 2016 ECR Plans) and LG&E's Projects 22, 23, and 26-28 (from LG&E's 2009, 2011, and 2016 ECR Plans) from their ECR mechanisms and monthly filings on a going-forward basis.[9] Eliminating these projects now is appropriate because they are now complete (or, in the case of LG&E Project 22, cancelled) and in service or will be before the end of the test year, their costs are mostly already recovered in base rates through a series of "roll-ins," and their elimination will simplify the oversight and administration of the Companies' ECR mechanisms. The Companies propose to recover the revenue requirements for the environmental compliance rate base associated with these projects through base rates and to continue to recover the revenue requirements of the remaining environmental compliance rate base through their ECR mechanisms (both the roll-in component and the monthly billing factor component).

[9] As indicated in the September 2012 expense month filing for the ECR monthly billing factor, Project 22 (construction of a new landfill at the Cane Run generating station) was cancelled.

Upon approval of new base rates, the Companies will continue to use the approved Environmental Surcharge ("ES") Forms in the monthly ECR filings but exclude the costs associated with these eliminated projects in the expense month associated with the change in base rates until the next two-year review, at which time the ES Forms will be modified to reflect the elimination of these projects.[10]

Q. Please explain how the ECR project eliminations impact revenues.

A. The ECR project eliminations result in rate base costs previously included for recovery in the ECR mechanism now being recovered as base rate costs. Therefore, the revenue requirement generated from these costs will now be recovered solely through base rates rather than through the ECR portion of base rates and the ECR Surcharge. As discussed in Mr. Seelye's testimony, Schedule M-2.3 for KU and Schedule M-2.3-E for LG&E electric show the reduction in base rate ECR revenues and ECR mechanism revenues and the corresponding increase in base rate revenues with no change in total revenues.

VIII. ELECTRIC COST OF SERVICE STUDIES, RATE DESIGN, AND ALLOCATION OF INCREASE

A. Electric Cost of Service Studies

Q. Did the Companies cause to be prepared an electric cost of service study for each of the Companies to guide their proposed rate designs and the allocation of their requested electric revenue increases?

[10] LG&E and KU incurred approximately $5 million and $9 million respectively in engineering and other costs related to the environmental control projects in their 2009 Environmental Compliance Plans during the base rate case test period ending April 30, 2008 and used for their 2008 base rate cases. These costs were included in base rates and excluded from ECR recovery when establishing the ECR cost levels for recovery in Case Nos. 2009-00197 and Case No. 2009-00198. Despite the proposed incorporation of certain projects from the 2009 ECR Plan in the pending cases, the Companies have continued to make an ECR rate base adjustment on Schedule B-2.2 consistent with the previous case. Accordingly, the Companies will continue to reduce ECR rate base in their monthly filings by the amount of the adjustment to ensure there is no over-recovery of costs.

A. Yes. At my direction, Mr. Seelye and The Prime Group conducted a fully allocated and time-differentiated embedded electric cost of service study for each of the Companies.

Q. Which cost of service methodology did The Prime Group use to perform the Companies' electric cost of service study?

A. At my direction, as discussed in Mr. Seelye's testimony, The Prime Group conducted the Companies' electric cost of service study using the loss of load probability ("LOLP") methodology. A utility's LOLP is the probability that a utility system's total demand will exceed its generation capacity over a given time period taking into consideration relevant factors, including the magnitude of the load and available generating capacity. Because the Companies plan their systems based largely on minimizing loss of load within reasonable economic constraints, an LOLP approach to conducting a cost of service study is appropriate. For the purposes of the Companies' LOLP studies, The Prime Group used hourly LOLP to allocate fixed production costs to the classes of customers. Because the Companies plan their generating units' production on an hourly basis, an hourly LOLP calculation is sensible and appropriate.

In compliance with the Commission's orders in the Companies' 2018 base rate cases regarding the Companies' use of the LOLP methodology, Mr. Seelye and The Prime Group conducted two additional cost of service studies for each of the Companies, namely a six-coincident-peak ("6-CP") study and a twelve-coincident-peak ("12-CP") study.[11] Although the Companies do not use such studies or their

[11] Case No. 2018-00294, Order at 19 (Ky. PSC Apr. 30, 2019) ("Therefore, the Commission finds that in KU's next base rate case that an alternative COSS should be filed along with the LOLP COSS."); Case No. 2018-00295, Order at 21 (Ky. PSC Apr. 30, 2019) ("Therefore, the Commission finds that in LG&E's next electric base rate case that an alternative COSS should be filed along with the LOLP COSS.")

analytical frameworks to plan their systems, the 6-CP and 12-CP methodologies are common in the industry and frequently introduced into the record of the Companies' base rate cases. Mr. Seelye's testimony explains those methodologies and why he believes (as do I) that the 6-CP approach produces more accurate cost-of-service results than does the 12-CP approach, as well as why the LOLP is superior to both of the other approaches.

As discussed in Mr. Seelye's testimony, the results of the LOLP and 6-CP cost of service studies are directionally similar. In this application, the Companies primarily relied on the results of the LOLP approach to allocate costs between rate classes but informed that allocation with the results of the 6-CP approach, as well as the ratemaking principle of gradualism. Mr. Seelye's testimony discusses the actual adjusted and proposed rates of return.

B. <u>Allocation of Electric Revenue Increases</u>

Q. What revenue increase is KU proposing for its operations?

A. As shown on Schedule M-2.1, KU is proposing an increase in forecasted test period revenues of $170,120,598, which is calculated by applying the proposed rates to forecasted test period billing determinants and including changes to miscellaneous operating revenues. This increase is less than the revenue deficiency of $170,477,290 shown in Schedule A because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule and the adjustment for the imputed revenues for the Solar Share Program, Business Solar, and Rate EVC-L2 discussed in the testimony of Mr. Seelye.

Q. What revenue increase is LG&E proposing for electric operations?

A. As shown on Schedule M-2.1-E, LG&E is proposing an increase in electric forecasted test period revenues of $131,073,276, which is calculated by applying the proposed rates to forecasted test period billing determinants and including changes to miscellaneous operating revenues. This increase is less than the revenue deficiency of $131,237,389 shown in Schedule A for electric operations because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule and the adjustment for the imputed revenues for the Solar Share Program and Rate EVC-L2 programs discussed in the testimony of Mr. Seelye.

Q. How do the Companies propose to allocate the electric revenue increase to the classes of service?

A. On average and setting aside the beneficial effect on customers of the Economic Relief Surcredit in the first twelve months of new rates, KU proposes to increase revenue across its rate classes by a system average of approximately 10.4 percent, and LG&E proposes to increase electric revenue across its rate classes by a system average of approximately 11.6 percent.

But the results of the Companies' cost of service studies show there are notable differences in the rates of return between the Companies' electric rate classes. This means there are some rate classes that are effectively subsidizing other rate classes. Although the Companies do not propose to eliminate all interclass subsidies in this proceeding, the Companies do propose generally to recover larger relative portions of the overall revenue increase from rate classes with lower rates of return and smaller relative portions of the proposed revenue increase from rate classes with higher rates of return. More specifically, Rate OSL (Outdoor Sports Lighting) for both Companies will have decreased rates; all lighting rates for KU, as well as Rates LE (Lighting Energy) and TE (Traffic Energy) for LG&E, will not have net increases (within rounding); all other standard rates for KU will have approximately equal percentage increases in revenues, and all other standard rates for LG&E will have approximately equal percentage increases in revenues. This approach comports with the longstanding ratemaking principle of gradualism and is consistent with the Companies' past rate allocation proposals where there have been significant differences in rates of return between rate classes. Mr. Seelye's testimony further discusses this approach.

C. Electric Rate Design Approach

Q. What is the basic objective of the rate design being proposed?

A. The Companies' proposed rate design continues to bring both the structure and the charges of the rate design in line with the results of the cost of service studies.

My testimony addresses this and other changes the Companies are proposing to rate structures and the charges supported by the cost of service study.

D. Residential Electric Rate Design and Increase

Q. Do the Companies propose to change their Residential Service (Rate RS) rate structure?

A. No. The rate structure will remain the same and consist of a daily Basic Service Charge and a flat volumetric, per-kWh energy charge, and will continue to be separated into Infrastructure and Variable components in the tariff.

Q. Do the Companies propose to bring the rate components in residential electric rates more in line with their cost of service studies?

A. Yes, although on a gradual basis. The Companies are proposing to increase the daily Basic Service Charge for Rates RS, Residential Time-of-Day Demand Service (Rate RTOD-Demand), Residential Time-of-Day Energy Service (Rate RTOD-Energy), and Volunteer Fire Department Service (Rate VFD) from $0.53 to $0.61 for KU, and from $0.45 to $0.52 for LG&E. As discussed in Mr. Seelye's testimony, KU's electric cost of service study indicates that the customer-related cost for the residential class is $0.82 per customer per day, and LG&E's electric cost of service study indicates that the customer-related cost for the residential class is $0.69 per customer per day. The Companies are therefore proposing to increase their residential Basic Service Charges in a direction that will more accurately reflect the actual cost of providing service but will still be less than the full amount of customer-related cost.

Also, the Companies' proposed Basic Service Charge increases follow the Commission's guidance in its final order in LG&E's most recent rate case that KU's and LG&E's residential Basic Service Charges should be the same percentage of their respective customer-related costs of service.[12] Here, the Companies' proposed residential Basic Service Charges are approximately 75% of their respective customer-related costs of service.

This cost is discussed more thoroughly in Mr. Seelye's testimony and is derived in his Exhibit WSS-2 for each of the Companies.

[12] Case No. 2018-00295, Order at 24-25 (Ky. PSC Apr. 30, 2019).

Q. Please explain the changes the Companies propose to make to the Rates RTOD-Demand and RTOD-Energy.

A. The Companies are adding an evening winter peak time (6:00 p.m. to 10:00 p.m.) to their existing morning winter peak time and revising the morning winter peak time to 6:00 a.m. to 10:00 a.m. in their RTOD rates. This change reflects the operational reality that the Companies typically experience two peak demand periods during winter days.

E. Infrastructure and Variable Components of Energy Charge

Q. What are the current and proposed Infrastructure and Variable components of the Companies' Rates RS, RTOD-Energy, RTOD-Demand, VFD, General Service (Rate GS), General Time-of-Day Demand Service (Rate GTOD-Demand), and General Time-of-Day Energy Service (Rate GTOD-Energy)?

A. The Companies' current and proposed Infrastructure and Variable components of their Rates RS, RTOD-Energy, RTOD-Demand, VFD, GS, GTOD-Demand, and GTOD-Energy are shown below. These components appear on the Companies' tariff sheets for informational purposes only.

KU

	Current ($/kWh)			Proposed ($/kWh)		
Rate	Infra.	Var.	Total	Infra.	Var.	Total
RS/VFD	0.05886	0.03077	0.08963	0.06750	0.03200	0.09950
RTOD-E (off- & on-peak)	0.02683 off 0.24465 on	0.03077	0.05760 off 0.27542 on	0.03312 off 0.18924 on	0.03200	0.06512 off 0.22124 on
RTOD-D	0.01276	0.03077	0.04353	0.01276	0.03200	0.04476
GS	0.08111	0.03114	0.11225	0.09216	0.03253	0.12469
GTOD-E (off- & on-peak)	N/A	N/A	N/A	0.04841 off 0.26776 on	0.03253	0.08094 off 0.30029 on
GTOD-D	N/A	N/A	N/A	0.03663	0.03253	0.06916

LG&E

	Current ($/kWh)			Proposed ($/kWh)		
Rate	Infra.	Var.	Total	Infra.	Var.	Total
RS/VFD	0.06072	0.03206	0.09278	0.07237	0.03245	0.10482
RTOD-E (off- & on-peak)	0.03874 off 0.17302 on	0.03206	0.07080 off 0.20508 on	0.04935 off 0.14704 on	0.03245	0.08180 off 0.17949 on
RTOD-D	0.02095	0.03206	0.05301	0.02095	0.03245	0.05340
GS	0.07247	0.03283	0.10530	0.09015	0.03340	0.12355
GTOD-E (off- & on-peak)	N/A	N/A	N/A	0.04735 off 0.21457 on	0.03340	0.08075 off 0.24797 on
GTOD-D	N/A	N/A	N/A	0.02610	0.03340	0.05950

IX. NET METERING

Q. Are the Companies proposing new net metering tariff provisions in these proceedings?

A. Yes. The Companies are each proposing a new net metering rate schedule, Rider NMS-2, and renaming their existing Rider NMS to Rider NMS-1. Rider NMS-1 will serve eligible electric generating facilities as defined in KRS 278.465(2) for which customers have submitted an application for net metering service before the effective date of rates established in these proceedings. Rider NMS-2 will apply to all other net metering customers.

The Companies are also proposing new terms and conditions for Net Metering Service Interconnection Guidelines, which I discuss further below in the context of the Commission's current administrative case on the same topic.

Q. Why are the Companies proposing Rider NMS-2?

A. The Companies' new net metering rate schedule, Rider NMS-2, is necessary to reflect changes in Kentucky law. In 2019, the General Assembly took an important step in enacting Senate Bill 100 (the "Net Metering Act") by reforming net metering policies and focusing on cost-based compensation for the energy produced onto the grid by customer-generators. Charged by the General Assembly to determine compensation for such energy, the Commission now has the express power to ensure a sustainable future for customer-generators that benefits all electricity customers. Effective January 1, 2020, the Net Metering Act defines "net metering" as "the difference between the: (a) Dollar value of all electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period and priced as prescribed in KRS 278.466; and (b) Dollar value of all electricity consumed by the eligible customer-generator over the same billing period and priced using the applicable tariff of the retail electric supplier."[13]

In delegating the authority to the Commission to establish the "dollar value" or set the rate to be used for the compensation of consumer-generators,[14] the General Assembly also established three essential rules for the billing and pricing of net electricity effective January 1, 2020. First, a retail electric supplier serving an eligible customer-generator is to compensate that customer for all electricity produced by the customer's eligible generating facility that flows to the retail electric supplier, as measured by the standard kilowatt-hour metering.[15] Second, for each billing period,

[13] KRS 278.465(4).
[14] KRS 278.466(3).
[15] KRS 278.466(2), (3).

compensation is to be provided to a customer-generator in the form of a dollar-denominated bill credit, which may be rolled over to the next bill if the credit exceeds the current bill.[16] Third, "[E]ach retail electric supplier shall be entitled to implement rates to recover from its eligible customer-generators all costs necessary to serve its eligible customer-generators, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators."[17]

Q. Please describe Rider NMS-1.

A. The Companies already serve a number of eligible customer-generators on their existing Rider NMS and will continue to serve these customers in the same way under the renamed Rider NMS-1 until 25 years from the effective date of rates established in these proceedings. Rider NMS-1 will remain available for eligible electric generating facilities for which customers have completed the Companies' net metering application before the effective date of rates established in these proceedings. These customers will continue to receive the kWh credit for electricity produced onto the Companies' grid for 25 years after the effective date of rates established in these proceedings, regardless of whether premises are sold or conveyed during that time period.[18] This proposal comports with the requirements of KRS 278.466.

Q. Please describe the proposed Rider NMS-2.

A. Rider NMS-2 is available to any eligible customer-generator operating an eligible electric generating facility located on the customer's premises on or after the effective

[16] KRS 278.466(4).
[17] KRS 278.466(5).
[18] KRS 278.466(6).

date of rates established in these proceedings. The Companies will bill each customer served under Rider NMS-2 in accordance with the customer's standard rate schedule, and the Companies will compensate the customer for energy provided to the Companies' system in the form of dollar denominated bill credits. It is important to note that, based on the Companies' proposal in these proceedings, customer-generators who size their generating systems to align the generation with their own consumption will continue to receive the same value for the energy consumed as other customer-generators served under Rider NMS-1.

Q. Please describe the energy credits under Rider NMS-2.

A. The Companies will provide a dollar denominated bill credit for each kWh of production that flows onto the Companies' grid. All kWh purchased by the Companies under NMS-2 will be purchased at a rate equal to the non-time differentiated rate set forth in Standard Rate Rider SQF, which is based on the Companies' estimated avoided cost for such generation. Any dollar credits in excess of the customer's bill amount will be carried forward to the customer's next bill. The customer's credit may be carried forward multiple months until the credit is exhausted. Once the customer's service is terminated, though, any unused credits will expire.

Q. Are the Companies proposing any different rates or rate structures for new net metering customers under KRS 278.466(6)?

A. Not at this time, though the Companies may do so in the future. As Mr. Seelye discuses in his testimony, the Companies believe their proposal for NMS-2 in these proceedings to compensate new net metering customers using dollar denominated bill credits that more accurately reflect the value of the energy those customers produce to the grid is a sufficient first step. It is also consistent with the ratemaking principle of gradualism and reduces intra-class subsidies net metering customers receive. And as noted above, customers who align generation with consumption will continue to receive the value of the retail rate for the generation consumed based on the proposal in these proceedings.

Q. Do the Companies' proposed net metering rate schedules consider externalities?

A. No. The Commission should not consider externalities in evaluating the cost-effectiveness of net metering rates. In denying to consider externalities in evaluating the cost-effectiveness of Demand Side Management programs, the Commission reiterated that it "has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service."[19] Considering these additional factors would conflict with the long-standing and proven ratemaking requirement that considers only known and measurable costs, create long-term customer cost recovery burdens, and increase customer rates. In Case No. 2019-00256, the Kentucky Office of Energy Policy ("OEP") similarly urged the Commission to continue using cost-based ratemaking principles in establishing net metering rates, warning that "utility rates are ineffective instruments by which to minimize social costs and maximize social benefits."[20] The Commission should not depart from this important requirement in

[19] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Order at 28 (Ky. PSC Oct. 5, 2018). *See also The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140, Order at 4 (Ky. PSC July 8, 2011) ("[I]ssues of environmental externalities, such as air and water pollution from generating electricity and mining fuel to supply the generating plants, are all issues beyond the scope of the Commission's jurisdiction.").

[20] *Electronic Consideration of the Implementation of the Net Metering Act*, Case No. 2019-00256, Initial Comments from the Kentucky Office of Energy Policy at 19 (Ky. PSC Oct. 10, 2019). The OEP is housed within the Kentucky Energy and Environment Cabinet.

developing the cost-based rates for the electricity put back onto the grid by customer-generators.

Q. Why are the Companies also proposing to update their net metering interconnection guidelines?

A. Updating the net metering interconnection guidelines is necessary because interconnected eligible customer generation transforms the distribution system from a one-way delivery mode into a complex two-way network for which electricity flows need to be carefully monitored and balanced and proper system protection applied. The new interconnection guidelines reflect issues presented by new technology, including changes to applicable industry standards (e.g., the National Electric Code).

The Companies are also proposing to eliminate net metering service application forms from their tariffs. In accordance with the Commission's previous orders, the application forms are, and will continue to be, available on the Companies' website (https://lge-ku.com/residential/net-metering). In addition, the Companies will provide paper applications to customers upon request. Removing the application forms from the Companies' tariffs helps reduce the tariffs' length and reflects the reality that customers interested in net metering service are tech savvy and are able to transact online.

To ensure ongoing compliance with the requirement of KRS 278.467(3) to file net metering application forms with the Commission, the Companies propose to file any future changes to their net metering application forms with the Commission in the most recent administrative case concerning net metering guidelines.

Q. Has the Commission also opened an administrative case concerning net metering interconnection guidelines?

A. Yes. On September 24, 2020, the Commission initiated Case No. 2020-00302 to investigate and potentially update net metering interconnection guidelines. The Companies will propose the same updated net metering interconnection guidelines in Case No. 2020-00302 and, if necessary, update the guidelines based on guidance from the Commission.

X. OTHER ELECTRIC RATE AND TARIFF CHANGES

A. <u>Small – Medium Business Customers</u>

Q. Please describe the Companies' proposed GTOD-Demand and GTOD-Energy rates.

A. The Companies propose to offer two new time-of-day rate schedules, Rates GTOD-Demand and GTOD-Energy. The two new rate schedules are structurally identical to the Companies' current Rates RTOD-Demand and RTOD-Energy for residential customers. Both of the new GTOD rates will be limited to Rate GS customers participating in the existing AMS Offering.

Q. Why are the Companies proposing Rates GTOD-Demand and GTOD-Energy?

A. The Companies have Rate GS customers participating in the AMS Offering. Although those customers have received some benefits from having advanced meters, such as better insight into their usage patterns, the new GTOD rates will allow these customers to enjoy potential savings and have more control over their bills by adjusting their usage in ways that benefit all customers. In addition, customers taking service under the new GTOD rates will provide useful data to the Companies when they create new rate offerings after their proposed AMI deployment. Therefore, the Companies are proposing Rates GTOD-Demand and GTOD-Energy to broaden their rate offerings for existing GS customers who are AMS Offering participants and to enhance the rate offerings for all similar customers when the AMI deployment is complete.

Q. Have the Companies made any revisions specific to Rate PS?

A. Yes. Rate PS currently mandates that a customer first taking service under that schedule must execute a contract for an initial term of one year. At the end of the initial term, the contract term is monthly. To afford the Companies greater flexibility in dealing with customers and addressing their unique circumstances, the provision has eliminated the mandatory requirement for a contract and permits the Companies to require a contract for an initial term at their discretion.

B. <u>Phasing Out Rate Grandfathering for Rates GS and PS</u>

Q. What is rate grandfathering, and how did it arise for the Companies' Rate GS and PS customers?

A. The Companies use the term "rate grandfathering" (or simply "grandfathering") to refer to an exemption allowing customers taking service under a rate schedule to continue doing so even after the availability terms change in a way that would otherwise exclude the grandfathered customers from taking service under that rate schedule.

For the Companies, grandfathering for Rates GS and PS arose in Case Nos. 2008-00251 and 2008-00252. In those cases, the Companies proposed significant revisions to their rate structures, eliminating certain rate schedules, proposing new rate schedules, and proposing revised eligibility criteria for certain of the rate schedules that remained.[21] To minimize the impact to customers that had taken service under predecessor rates to Rates GS and PS, the Companies permitted customers that had been served under rates similar to GS and PS as of February 6, 2009, but did not qualify for service under the new availability terms to be grandfathered onto GS and PS. Customers could also elect to take service under another rate schedule for which they did qualify under the new availability terms.

In the Companies' 2012 base rate cases (Case Nos. 2012-00221 and 2012-00222), the Companies added text to the availability provisions of Rates GS and PS to begin to reduce the number of grandfathered customers.[22] The added text, which remains in the Companies' current and proposed tariffs, states that grandfathered customers that elect to take service on another rate schedule for which they qualify cannot later take service under their previously grandfathered rate unless and until they meet the availability requirements of the rate. For example, a customer that had been grandfathered onto Rate GS and had an annual average demand of 75 kW could elect to take service under Rate PS. If the customer made that change, the customer could not choose to switch back to Rate GS unless and until its average demand decreased to 50 kW or less, even though the customer had been previously grandfathered.

Q. How many customers are currently grandfathered?

A. A total of 1,254 KU and 802 LG&E customers now receiving service under Rate GS were eligible for such service in 2009 only as a result of the grandfather provision. Of

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[21] *See Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2008-00251, Application (Ky. PSC July 29, 2008); *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, Case No. 2008-00252, Application (Ky. PSC July 29, 2008).

[22] *See Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2012-00221, Application (Ky. PSC June 29, 2012); *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2012-00222, Application (Ky. PSC June 29, 2012).

this number, approximately 442 KU and 247 LG&E customers are currently eligible for service under Rate GS based upon their current usage patterns without regard to the grandfathering provision.

Approximately 847 KU and 480 LG&E customers currently served under Rate PS were eligible for such service under that rate schedule in 2009 only because of the grandfathering provision. Of this number, approximately 93 KU and 97 LG&E customers meet the availability requirements for service under Rate PS without relying upon the grandfathering provision.

Q. How does grandfathering affect those customers?

A. It affects different grandfathered customers differently:

1. Some grandfathered customers did not qualify for their rate schedules after the availability criteria changed on February 6, 2009, but their load characteristics have since changed so that they now qualify for their rate schedules. Today, such customers have a right to remain on their current rates even if their usage characteristics subsequently change again so that they no longer satisfy the criteria for being on the rate schedules.

2. Some grandfathered customers currently do not meet the criteria for being on their current rate schedules and would likely benefit financially from changing to the rate schedules for which they now qualify.

3. Some grandfathered customers currently do not meet the criteria for being on their current rate schedules and would likely find it financially disadvantageous to change to the rate schedules for which they now qualify.

It is important to note that customers who qualified for the rate schedules under which they took service in February 2009 under the changed criteria that then took effect are not grandfathered; rather, as the Companies' tariffs have continuously reflected since February 2009, if such customers' load characteristics change such that the customers no longer qualify for service under their current rates, the Companies will move such customers to the appropriate rates for their demand characteristics. For example, a secondary customer with a 12-month average maximum load of 30 kW who took service under Rate GS on February 6, 2009, was not grandfathered onto Rate GS, but rather continued to take service under Rate GS as a customer fully eligible to do so. But if that customer's 12-month average maximum load subsequently climbed to 100 kW, the Companies would transfer the customer to Rate PS.

Q. What do the Companies propose in these proceedings concerning grandfathering for Rates GS and PS?

A. The Companies' current tariffs state that grandfathered customers under Rates GS and PS cease to be grandfathered when they elect to take service under another rate schedule. This has helped to phase out grandfathering for some customers over time as they choose to move between rate schedules.

In these proceedings, the Companies propose to retain their current phase-out provision with additional clarifying terminology, but they propose also to add a provision to remove grandfathered status from grandfathered customers that meet the availability requirements of their rate schedules on the date new rates go into effect from these proceedings. To determine whether grandfathered customers meet the applicable availability requirements, the Companies will examine the affected customers' usage data for the 12 months ending January 31, 2020.[23] For example, if a grandfathered Rate GS customer had a 12-month average maximum load of 75 kW on February 6, 2009, but had a 12-month average maximum load of 40 kW for the 12 months ending January 31, 2020, the customer would no longer be grandfathered when new rates go into effect following these proceedings. This approach would eliminate grandfathering for 442 KU and 247 LG&E Rate GS customers and 93 KU and 97 LG&E Rate PS customers.

C. Lighting and Pole Attachments

Q. What revisions do the Companies propose to make to Rate LS (Lighting Service) and Rate RLS (Restricted Lighting Service)?

A. The Companies propose several revisions to the Rates LS and RLS. Customers will be given the option of paying a one-time conversion fee to change a current functioning non-LED (light emitting diode) fixture to an LED fixture. Currently Rate LS provides for a monthly conversion fee to be paid for a period for 60 months. Customers have requested the option of making a one-time payment in lieu of payments spread over 60 months. With either option, the conversion fee represents the class average remaining book value of the current working non-LED fixtures.

The Companies will have two additional LED fixture offerings under Rate LS: Victorian (KU only) and London (both Companies). The High-Pressure Sodium Victorian fixtures will no longer be available.

The Companies are also adding a Wood Pole Charge for overhead service.

[23] The Companies will use data for the 12 months ending January 31, 2020, to avoid the effects of COVID on customers' usage data.

Spot replacements under Rate RLS will only be available for bulbs. In the event restricted fixtures or poles fail, the customer will have the option of having the failed fixture or pole removed or having the failed fixture or pole replaced with a comparable LED fixture or pole.

Customers requesting removal of an existing Rate RLS lighting system will no longer be required to pay the cost of removing the facilities; removal costs will be incorporated into Rate RLS. A customer who subsequently requests the installation of an LED replacement within five years, however, may be required to pay a conversion fee.

Finally, the Companies propose revisions to Rate LS regarding when a customer must enter a contract for service. Currently, a customer must execute a written contract when additional facilities are required to provide the service. Under the proposed revisions, customers will also be required to execute a contract when an installation included new underground-fed lights, three or more overhead lights, or the customer requests a conversion to LED lights.

Q. What revisions are proposed to Rate TE (Traffic Energy Service)?

A. Rate TE, which governs service to traffic control devices and other similar devices, currently provides that a customer must have an attachment agreement to attach a device to the Companies' facilities. Because the Companies' Rate PSA (Pole and Structure Attachments) specifically governs attachments made to the Companies' poles and structures and is more detailed and specific regarding attachment agreements, the provision in Rate TE is unnecessary and has been deleted.

Q. What revision is proposed to Rate PSA (Pole and Structure Attachment Charges)?

A. The Companies propose to make only one change to Rate PSA at Sheet No. 40.8, which is to treat an application or applications for more than 30 wireless attachments in a 30-day period as a high-volume application. The Companies are proposing this change due to the amount of work required to review each proposed wireless attachment.

The Companies are aware of, and have provided comments on, the Commission's proposed Access and Attachments to Utility Poles and Facilities regulation. The Companies will make changes to Rate PSA as needed when the new regulation becomes final.

Q. What revisions have the Companies made to Rate OSL (Outdoor Sports Lighting Service)?

A. The peak period for the Summer Peak Months of May through September has been reduced by one hour from 1:00 p.m. to 7:00 p.m. on weekdays to 1:00 p.m. to 6:00 p.m. This change recognizes the effect of earlier sunsets in the late summer and early fall months on the electric usage of outdoor fields used for organized competitive sports, such as high school football and soccer.

D. <u>Electric Vehicles</u>

Q. Are the Companies proposing revisions to their tariffs regarding the provision of electric charging equipment and charging services to electric vehicles?

A. Yes. Under Electric Vehicle Supply Equipment – Rider (Rider EVSE-R), the Companies provide charging stations behind customers' meters that customers can use to charge electric vehicles ("EVs"). Under Rider EVSE-R, the Companies bill the customers a monthly fixed charge for the use of the charging station; the customer is responsible for providing the electric energy for the charging station by purchasing it from the Companies under the applicable rate schedule, self-providing the energy through onsite generation, or a combination of the two.

Pursuant to Rate EVSE, the Companies provide an unmetered charging station that customers can use to charge EVs. Under this rate schedule, the Companies provide the energy for the charging station, the cost of which is bundled into the monthly fixed charge.

Currently, the Companies offer only the single- and dual-charger versions of the ChargePoint CT 4000 charging station ("Level 2 charging station") under Rate EVSE and Rate EVSE-R. The Companies are proposing in these proceedings to offer additional charging-station options, namely single- and dual-charger versions of the Clipper Creek HCS-40 charging station ("Level 3 charging station"), giving customers who are considering installing EV charging stations greater choice and flexibility. Because of differences in the charging stations, the rate for the Level 3 charging stations will differ from that currently charged for the Level 2 charging stations. Rate EVSE and Rate EVSE-R will be revised to include a rate for the single- and dual-charger versions of the Level 2 charging stations. Mr. Seelye's testimony explains how the rates for the Level 3 charging stations were developed.

Q. Do the Companies propose any revisions to their Electric Vehicle Charging Rate (Rate EVC)?

A. Yes. Currently the Companies provide direct charging services to EVs through 20 Level 2 charging stations located within their territories. These charging stations charge a vehicle from a 240V outlet and will typically charge a vehicle at a rate between

12 to 60 miles of range per hour. A customer using one of these stations is assessed a fee under Rate EVC based upon the time the customer's EV is connected to the charging station, currently $0.75 for the first two hours of charging service and $1.00 for all additional charging hours.

As Ms. Saunders and Mr. Seelye describe in detail in their testimonies, the Companies intend to begin installing Level 3 charging stations (or "DC Fast Charging Stations") in the second half of 2022. A DC Fast Charging Station is a primary voltage charger that uses a direct current ("DC") circuit to charge a plug-in electric vehicle and can provide around 170 miles of range in about 30 minutes.

Because of the differences between Level 2 charging stations and DC Fast Charging Stations, Rate EVC is not appropriate for service provided through DC Fast Charging Stations. Therefore, the Companies propose to establish Rate EVC-FAST to govern service provided by a DC Fast Charging Station and to rename the existing Rate EVC to be Rate EVC-L2. The rate for service under Rate EVC-FAST would be $0.25 per kWh of energy used. It would not be based upon the time an EV is connected to a charging station. Mr. Seelye's testimony explains in greater detail the basis for using different pricing structures. Except for the differences in the rate structure, Rate EVC-FAST will have the same terms found in Rate EVC-L2.

E. <u>Special Charges</u>

Q. Please describe the Advanced Meter Opt-Out Charges.

A. The Advanced Meter Opt-Out Charges will allow customers to request metering that does not utilize two-way communications, limited only by the Companies' operational and safety requirements. Mr. Seelye's testimony and his Exhibit WSS-19 provide the calculations and cost support for these charges.

As shown in the KU Advanced Meter Opt-Out Charges, KU customers electing to opt out will pay a set-up charge and a recurring monthly charge related to ongoing costs of opt-outs, including meter reading costs. LG&E customers electing to opt out will pay similar charges, though there are different amounts for electric customers and gas customers. The table below summarizes the proposed per-meter charges:[24]

Utility Service	Opt-Out Set-Up Charge	Recurring Monthly Opt-Out Charge
KU	$39.00	$15.00
LG&E electric	$35.00	$12.00
LG&E gas	$33.00	$5.00

A customer desiring to opt out any meter on a single premise must opt out—and pay separate opt-out charges for—all meters on that premise, including electric and gas meters for LG&E customers with both services.

Q. Why and when will customers opting out of AMI be assessed opt-out charges?

A. The Companies are proposing AMI opt-out charges in accordance with the Commission's order in its most recent smart grid administrative case: "The Commission finds that any opt-out provision should require those customers that opt out to bear the cost related to that decision- through a one-time fee and/or a monthly charge, as appropriate."[25] Therefore, as shown in the cost support provided in Mr.

[24] The only exception to applying opt-out charges on a per-meter basis concerns the small number of situations in which the Companies currently bill multiple meters on a combined basis for operating convenience. *See* Kentucky Utilities Company, P.S.C. No. 18, Original Sheet No. 101.1; Louisville Gas and Electric Company, P.S.C. Electric No. 11, Original Sheet No. 101.1; Louisville Gas and Electric Company, P.S.C. Gas No. 11, Original Sheet No. 101.1. The Companies will apply only one opt-out set-up charge and one monthly charge in each such situation. For expediency and overall clarity, the Companies refer to the opt-out charge as a per-meter charge throughout their application and testimony in this proceeding.

[25] *Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No, 2012-00428, Order at 17 (Ky. PSC Apr. 13, 2016).

Seelye's Exhibit WSS-19, all of the opt-out charges the Companies propose are based on costs created by customers choosing to opt out of the AMI deployment. The set-up charge will cover all the costs associated with a meter that does not utilize two-way communications, e.g., system set-up and license fees for systems needed for the non-communicating meter, as well as costs to change the meter. The Companies propose that a customer pay the opt-out set-up charge once for each meter the customer seeks to opt out. For example, if a residential customer opts out the meter at the customer's residence and pays the opt-out set-up charge, the customer will have to pay the charge again if the customer moves and seeks to opt out at the new residence.

But the Companies propose to have an initial period during which customers may request to opt out and avoid the set-up charge. A customer requesting opt-out before AMI meter installation at the customer's premise will not incur the set-up charge; a customer requesting opt-out after AMI meter installation at the customer's premise will incur the set-up charge.

In addition to the opt-out set-up charge, the Companies propose to implement a recurring monthly opt-out charge that will take effect for all opted out meters within a particular deployment area following the full deployment of AMI in that particular deployment area and validation of the meter-data-management and related systems in that area. The recurring monthly charge will cover the ongoing costs of opt-outs, including the cost of manual meter reading.

In addition to the customers' ability to choose to opt out of the AMI deployment, the Companies may require a customer to opt out if the customer has a history of particularly dangerous or repeated meter tampering. This will allow the

Companies to maintain regular on-site visits to such customers to ensure safe, reliable, and accurate service. For the same reasons, the Companies may refuse to allow a customer to opt out if the customer has a history of tampering, if having a non-communicating meter could create a hazard for the customer, the Companies' personnel, or others, or if the customer impedes the Companies' ability to access and read the meter.

The Companies believe this opt-out approach accords with the Commission's position in its final order in its 2012 administrative case on smart grid matters: "The Commission finds that any opt-out provision should require those customers that opt out to bear the cost related to that decision—through a one-time fee and/or a monthly charge, as appropriate."[26] In particular, the Companies' proposed opt-out charges align with the Commission's cost-based requirement.

Also, creating a disincentive to opt out, albeit one purely based on costs created by opting out, provides benefits to the vast majority of customers who will not opt out. As the Commission has recognized, a smart-meter deployment creates the greatest operational benefits relative to its costs if it is ubiquitous.[27]

Q. Has the Commission considered and approved other smart meter opt-out tariffs?

A. Yes. In Case No. 2016-00152, the Commission considered Duke Energy Kentucky's ("Duke Kentucky") Electric AMI Opt-Out Program Tariff ("Rider AMO"). Rider AMO provides that a residential customer may opt out of AMI for one-time fee of $100 (post-deployment; there is not a one-time fee for those who opt out pre-deployment)

[26] *Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, Order at 17 (Ky. PSC Apr. 13, 2016).
[27] *Id.*

and a $25 monthly charge. The parties reached a stipulation, which provided in relevant part that Duke Kentucky would implement Rider AMO. The Commission approved the stipulation.[28]

The Companies' proposed Advanced Meter Opt Out Charges are structurally similar to Duke Kentucky's approved Rider AMO, though the charges differ to reflect the Companies' costs of opt-outs. This supports the reasonableness of the Companies' proposed opt-out approach.

Q. Please explain the Companies' proposed changes to their Disconnect/Reconnect Service Charge (Sheet No. 45).

A. One feature AMI will provide is the ability to remotely disconnect and reconnect electric service. (For safety reasons, the Companies are not proposing to deploy this capability for gas service.) This remote electronic capability will allow the Companies to eliminate disconnection and reconnection charges for customers with advanced meters while also allowing service disconnections and reconnections to occur more rapidly. The ability to reconnect service rapidly is an important benefit; when customers who are disconnected for nonpayment become eligible for service reconnection, AMI will permit that reconnection to happen in a matter of minutes rather than hours.

Q. What changes to the Companies' service disconnection and reconnection policies are the Companies proposing in this proceeding in connection with full AMI deployment?

[28] Case No. 2016-00152, Order (Ky. PSC May 25, 2017).

A. The Companies are not proposing to change any of their service disconnection or reconnection policies due to AMI.

Q. What is the Companies' policy regarding disconnection of service for non-payment?

A. The Companies' policy regarding disconnection of service for non-payment is fully set out in the Companies' tariffs, which the Companies do not propose to amend in this proceeding:

> Company shall have the right to discontinue service for non-payment of bills after Customer has been given at least ten days written notice separate from Customer's original bill. Cut-off may be effected not less than twenty-seven (27) days after the mailing date of original bills unless, prior to discontinuance, a residential customer presents to Company a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the original date of discontinuance. Company shall notify Customer, in writing, (either mailed or otherwise delivered, including, but not limited to, electronic mail), of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance.[29]

In addition, the Companies have been, and will continue to be, obligated to comply with the Commission's regulations concerning refusal or termination of service, particularly 807 KAR 5:006, Section 15.

Q. Do the Companies propose to modify or amend their cold-weather disconnection policy?

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[29] Kentucky Utilities Company, P.S.C. No. 18, Original Sheet No. 105.1; Louisville Gas and Electric Company, P.S.C. Electric No. 11, Original Sheet No. 105.1; Louisville Gas and Electric Company, P.S.C. Gas No. 11, Original Sheet No. 105.1.

A. No. The Companies' cold-weather disconnection policy, which the Companies do not propose to change, is below:

> **Policy for Residential Disconnects During Periods of Cold Weather**
>
> **Overview:**
>
> These guidelines apply only to residential disconnections for non-payment and do not apply to disconnections of unauthorized reconnects (UARs) or disconnections necessary due to other dangerous conditions. The Companies will continue to disconnect UARs regardless of weather conditions because they cannot condone a practice that places the person performing the UAR at immediate risk of permanent injury.
>
> **Cold Weather Periods:**
>
> Non-payment disconnections should not be initiated when the National Weather Service (NWS) predicts a daily high temperature below 32 degrees for a 24-hour period. It is suggested that non-payment disconnections not occur on the last workday of the week when the weekend forecast calls for temperatures that fall below 32 degrees. In addition, disconnections may be suspended during the workday should temperatures abruptly drop below the original NWS forecast.

As is true for service disconnections generally, the Companies will continue to comply with the Commission's regulations concerning winter hardship reconnection of service, particularly 807 KAR 5:006, Section 16.

In short, the Companies are proposing absolutely no changes to their policies regarding service disconnection and reconnection. The only practical change will be that electrical service disconnections and reconnections will be done remotely for AMI-equipped customers, improving the speed and reducing the cost of such services. Also, remote service switching capability has other benefits, including more rapid service reconnections when payments have been made, as well as potential safety benefits for customers and the Companies' personnel.

Q. Describe the Companies' proposed revisions to Meter Pulse Charge.

A. The Companies propose to reduce the charge from $24 per month to $21 per month. In addition, customers desiring meter-pulse data would be required to enter into a contract for a minimum term of one year and provide at least 90 days' notice prior to termination. These new requirements will help ensure the Companies recover costs associated with provisioning their systems to provide pulse data and reconfiguring their systems to cease to provide that data when customers terminate the data service.

The Companies have further proposed limits on their liability for damages resulting from their meter pulse data or the service in general.

F. <u>Qualifying Facilities (Rider SQF and Rider LQF)</u>

Q. Are any revisions proposed to the Companies' riders governing qualifying facilities?

A. Yes. Two minor revisions have been made for the purpose of clarity. The Companies have revised Small Capacity Cogeneration and Small Power Production Qualifying Facilities (Rider SQF) to clarify that legal holidays that fall on weekdays will be considered a weekday for purposes of determining on-peak periods. They have also revised Large Capacity Cogeneration and Small Power Production Qualifying Facilities (Rider LQF) to clarify the definition of "hourly avoided energy cost." Currently that cost is equal to the "Company's actual variable fuel expenses, for Company-owned coal and natural gas-fired production facilities, divided by the associated megawatt-hours of generation, as determined for the previous month." "Actual variable fuel expenses" has been revised to read "actual fuel expenses, excluding those that are fixed and non-variable."

G. Rider GT (Green Tariff)

Q. Have the Companies proposed revisions to Rider GT in this proceeding to comply with the Commission's May 8, 2020 order in Case No. 2020-00016?

A. No. In its May 8, 2020 order in Case No. 2020-00016, the Commission found that Rider GT Option #3 did not "contain sufficient parameters and clarity to provide industrial customers with regulatory certainty that the Commission will approve the RPAs [Renewable Power Agreements]." It directed the Companies make several modifications to Option #3 in their next rate proceeding or by October 1, 2020, whichever occurred first. On September 30, 2020, the Companies filed their proposed modifications to Option #3 and received acceptance for them to be effective November 1, 2020. The Companies' proposed electric tariffs in these proceedings reflect those modifications as required by the May 8, 2020 order in Case No. 2020-00016.

H. Excess Facilities Rider

Q. Please describe the Companies' revisions to the Excess Facilities Rider (Rider EF).

A. The Companies have added a sentence to the Terms of Contract section to clarify that Excess Facilities customers who request the facilities be removed are responsible for the actual cost of removing the facilities they ask the Companies to install. Because the kinds of facilities and their costs of removal can vary significantly under Rider EF, it is more equitable, and it produces more accurate rates, to have each customer be responsible for removal costs than to attempt to incorporate an average cost of removal into the rate calculation.

I. Economic Development Rider

Q. Have the Companies made any revisions to Economic Development Rider (Rider EDR)?

A. Yes. One item has been revised, and two additional terms and conditions have been added to the Economic Development Rider. The revision concerns applications for EDR service, which the Companies would broaden to include a certification of qualification for benefits from any program reviewed and approved by the Kentucky Economic Development Finance Authority or any successor agency. The first addition requires that all EDR contracts provide for the recovery of EDR customer-specific fixed costs over the life of the contract. The second addition requires a customer seeking an EDR contract designed to retain the load of existing customers to provide an affidavit stating that, without the rate discount, its operations would cease or be severely restricted and to demonstrate financial hardship to Company. These revisions help ensure that other customers do not subsidize EDR customers and that EDR contracts for customer-retention purposes are indeed helping retain customers rather than simply giving them a rate discount, consistent with the Commission's final order in Administrative Case No. 327.[30]

J. <u>Warranty Service for Customer-Owned Exterior Electric Facilities (Rider WT)</u>

Q. Please describe Rider WT.

A. The Companies are proposing a new Standard Rate Rider, Rider WT, which provides the terms under which the Companies may perform billing and collection services for firms providing warranty service to the Companies' residential customers for the repair or replacement of customer-owned exterior electric facilities serving the customer's residence and connected to the Companies' distribution facilities.

[30] *An Investigation into the Implementation of Economic Development Rates by Electric and Gas Utilities*, Admin. Case No. 327, Order (Ky. PSC Sept. 24, 1990).

Under Rider WT, a firm providing warranty service to the Companies' residential customers for the repair or replacement of customer-owned exterior electric facilities may contract with the Companies for billing and collection services. The contract between the Companies and the firm providing the warranty service will establish the specific terms of the service. The Companies will bill the warranty service fee as a separate line item on the customer's bill and will clearly identify the nature of fee.

Rider WT provides customer payments will be applied in the following order of priority: (1) amounts owed to the Companies for current billing period; (2) unpaid balance for electric service provided in prior billing periods; and (3) fees, including any warranty service fees or taxes collected for other entities.

Q. If a customer fails to provide the fee for the warranty service, will the customer's service be terminated?

A. No. Rider WT expressly prohibits the termination of a customer's service for failure to pay a warranty fee.

Q. What is the fee or charge for the firms using the Companies' billing and collection services under Rider WT?

A. Under the terms of Rider WT, the Companies will establish a fee through negotiation with the firm requesting the service.

Q. Why are the Companies offering this service?

A. Ms. Saunders's testimony explains that the Companies' arrangement with HomeServe USA provides a significant benefit to customers in the form of a rapid and professional response when requiring repairs to or replacement of their customer-owned exterior electric facilities and affords an easy and simple means for Companies' customers to arrange payment for that service. To the extent that Rider WT facilitates other reputable and responsible firms also to provide this service to the Companies' customers, the Companies' customers further benefit.

K. Late Payment Charges for Non-Residential Customers

Q. What is the Companies' proposal regarding late payment charges for non-residential customers?

A. In their 2018 rate case proceedings, the Companies received approval to waive late payment charges for residential customers if a customer requests it and has not incurred a late payment charge in the previous eleven billing cycles. The Companies now propose to waive late payment charges under the same terms for non-residential customers served under any of the following Rate Schedules: VFD, GS, GTOD-Demand, GTOD-Energy, PS, AES, TODS, TODP, RTS, FLS, and OSL. The Companies propose to permit only one such waiver per twelve billing cycles. This proposal would allow non-residential customers who ordinarily pay on time but occasionally pay late not to be charged while retaining a general incentive for customers to pay on time.

For the purposes of calculating their revenue requirements in these proceedings, the Companies are not assuming any late payment charge waivers and accordingly have not reduced miscellaneous revenues. In addition, the Companies are not seeking regulatory asset treatment for late payment charge waivers the Companies ultimately grant.

L. <u>Revisions to Electric Terms and Conditions</u>

Q. Please identify any significant revisions made to the Companies' Terms and Conditions for the provision of electric service.

A. The Companies have made the following revisions to their Terms and Conditions of Service:

- The definition of "Single Family Unit" is revised to make clear that "separately metered vacation rentals, boat slips, campers or any other structure without a permanent foundation" are not single-family units and are not eligible for residential service.
- "Customer Responsibilities" now makes clear that a customer is required to grant at no cost to the Companies such easements and rights-of-way on and across the customer's property that are reasonably necessary for the Companies to provide service to that customer.
- The definition of the entities entitled to priority for service restoration and energy curtailment has been made more specific.
- The Customer Bill of Rights set forth in the Companies' Terms and Conditions has been revised to provide that, when the cause for a customer's discontinuance of service has been resolved, the customer has the right to prompt restoration of service within 24 hours or by the end of the next business day, whichever is greater.
- The provision regarding proration of bills has been revised to provide that, if the total period between regular and special meter readings for an opening or closing bill is less than 30 days, any demand or monthly charge of the

applicable rate schedule will be prorated on the basis of the ratio of the actual number of days in such period to 30 days.

Q. Have the Companies made any other changes to their electric tariffs?

A. Yes. The Companies have made a number of small edits to clarify certain issues and make clean-up edits throughout their tariffs.

XI. GAS COST OF SERVICE STUDY, RATE DESIGN, AND ALLOCATION OF INCREASE

A. Gas Cost of Service Study

Q. What methodology did LG&E use in its gas cost of service study?

A. In general, the methodology used followed the electric cost of service study, though the gas cost of service study is not time-differentiated. This methodology for the gas cost of service is consistent with prior rate cases, including the refinement made in LG&E's 2018 rate case concerning the way that transmission costs are allocated in the study. The details of that study are presented in the testimony of Mr. Seelye, as are the actual adjusted and proposed rates of return.

B. Allocation of Gas Revenue Increase

Q. What revenue increase is LG&E proposing for gas operations?

A. As shown on Schedule M-2.1-G, LG&E is proposing an increase in gas forecasted test period revenues of $29,988,054, which is calculated by applying the proposed rates to forecasted test period billing determinants. This increase is slightly lower than the revenue deficiency of $29,989,470 shown in Schedule A for gas operations because the number of decimal places in the proposed charges cannot be carried out far enough to yield the exact amount shown in the schedule.

Q. How does LG&E propose to allocate the gas revenue increase to the classes of service?

A. As Mr. Seelye's testimony demonstrates, there are significant differences in the rates of return for LG&E's gas rate classes. To bring the rates of return closer to the system average and gradually reduce interclass subsidies, LG&E proposes to recover the revenue increase by setting rates to remove 25% of the current subsidy for Rates RGS, AAGS, and FT, give no increase to Rate IGS, and recover the balance of the increase from Rate CGS. This approach mitigates, but does not eliminate, all interclass subsidies in this proceeding. Mr. Seelye's testimony further discusses the details of his study that supports this approach.

C. Residential Gas Service

Q. Does LG&E propose to bring the rate components in residential gas rates more in line with the cost of service study?

A. Yes. LG&E is proposing a daily Basic Service Charge of $0.78 for Rates RGS and VFD, which is an increase from the current daily Basic Service Charge of $0.65. As Mr. Seelye discusses further in his testimony, the cost of service study indicates that the customer-related cost for the residential class is $0.98 per day. LG&E is therefore proposing to increase the Basic Service Charge in a direction that will more accurately reflect the actual cost of providing service but will still be less than the full amount of customer-related cost. This cost is derived in Mr. Seelye's Exhibit WSS-15.

XII. OTHER GAS RATE AND TARIFF CHANGES

Q. Please describe the change made to Rate AAGS (As-Available Gas Service).

A. LG&E modified the provisions related to its right to discontinue service to customers under Rate AAGS to clarify that it may discontinue service to one or more customers served under this rate schedule without also discontinuing service to all customers served under that schedule.

Q. Please describe the revisions proposed for Rate FT (Firm Transportation Service).

A. The proposed revisions require that gas generators irrespective of the size or purpose of the generator take service for those facilities under Rate CGS, Rate IGS, or Rate DGGS, as applicable, if those generation facilities are installed and operating 90 days after January 1, 2021. The proposed revisions also add clarifying language to the section on "Variation in MMBTU Content" regarding the price to cash-out such variations.

Q. What revisions has LG&E made to Rate LGDS (Local Gas Delivery Service)?

A. It has added clarifying language to the section on "Variation in MMBTU Content" regarding the price to cash-out such variations. It has also made several revisions to the "Gas Quality" section to ensure that any gas received pursuant to Rate LGDS will not harm customers, employees, contractors, or LG&E's gas distribution system.

Q. What revisions has LG&E made to Rate PS-TS-2 (Pooling Service Rider TS-2)?

A. It has added clarifying language to the section on "Variation in MMBTU Content" regarding the price to cash-out such variations. Special Term and Condition No. 5's provisions regarding payment have been replaced with provisions similar to those in other rates schedules.

Q. Describe the revisions made to Rate PS-FT (Pooling Service -Rate FT).

A. Special Term and Condition No. 6's provisions regarding payment have been replaced with provisions similar to those in other rates schedules.

Q. What revisions were made to Rate NGV (Natural Gas Vehicle Service)?

A. A disclaimer of liability and responsibility was added to this rate schedule regarding the fitness of any gas provided under this schedule as a fuel in vehicular internal combustion engines.

Q. Were any revisions made to LG&E's Gas Supply Clause?

A. Yes. The Gas Supply Clause (GSC) was clarified to allow for the recovery through the GSC of the costs associated with vaporized liquefied petroleum gas and air and liquefied natural gas.

Q. Which rate base items is LG&E removing from Adjustment Clause GLT (Gas Line Tracker)?

A. Effective July 1, 2021, LG&E is removing from the GLT rate base the Steel Customer Service Lines and Targeted Removal of County Loops and Steel Curbed Services Program ("Steel Services Program") and the Transmission Modernization Program and will recover those costs through the proposed change in base rates. These programs are being eliminated from GLT rate base because the Steel Services Program expires at the end of the test year and the Transmission Modernization Program is expected to be complete at the end of the test year. Furthermore, because the Transmission Modernization Program is being removed from GLT rate base, the corresponding volumetric charge will be reduced to only recover costs incurred through June 30, 2021. Once these costs have been recovered, the GLT transmission charge will be changed to zero in a future tariff filing. Other GLT projects that will be removed from GLT rate base due to their completion include the Main Replacements portion of the Leak Mitigation Project and the Aldyl-A Mains and Services Replacement Project.

Q. Please explain the process used to update the GLT rates.

A. The Companies update the GLT rates and file the updated rates with the Commission in February each year with an effective date of May 1. Because of the timing of the annual GLT filing and the likely timing of the pendency of these proceedings, LG&E is filing updated GLT rates in this rate case that assume the Commission will approve removing the projects described above. The Companies have adjusted the current GLT rates as approved on April 28, 2020, for the removal of the specific projects.[31] LG&E will make its usual GLT Annual Filing in February 2021 that will continue to include the projects since the elimination to base rates has not been approved. LG&E will make a GLT rate reconciliation or tariff filing as needed following the conclusion of its base rate case.

Q. Please explain how the GLT project eliminations impact revenues.

A. The GLT project eliminations result in rate base assets previously included for recovery in the GLT mechanism now being recovered as base rate assets. Therefore, the revenue requirement generated from these assets will now be recovered solely through base rates rather than through the GLT charge. As discussed in Mr. Seelye's testimony, Schedule M-2.3-G for LG&E gas shows the reduction in GLT mechanism revenues and the corresponding increase in base rate revenues with no change in total revenues.

Q. What is LG&E's proposal regarding late payment charges?

A. In its last rate case proceeding, LG&E received approval to waive late payment charges for residential customers if the customer requests it and has not incurred a late payment

[31] *Electronic Application of Louisville Gas and Electric Company for Approval of Revised Rates to be Covered Through its Gas Line Tracker Beginning with the First Billing Cycle for May 2020*, Case No. 2020-00032, Order (Ky. PSC April 28, 2020).

charge in the previous eleven billing cycles. It now proposes to waive late payment charge under the same terms for non-residential customers served under any of the following Rate Schedules: VFD, CGS, IGS, AAGS, SGSS, FT, or DGGS. LG&E proposes to permit only one such waiver per twelve billing cycles. This proposal would allow non-residential customers who ordinarily pay on time but occasionally pay late not to be charged while retaining a general incentive for customers to pay on time.

For the purposes of calculating its gas revenue requirement, LG&E is not assuming any late payment charge waivers and accordingly has not reduced miscellaneous revenues. In addition, LG&E is not seeking regulatory asset treatment for late payment charge waivers it ultimately grants.

Q. Please identify any significant revisions made to LG&E's Terms and Conditions for the provision of gas service.

A. LG&E has made the following revisions to its Terms and Conditions of Service for gas service:

- "Customer Responsibilities" now makes clear that a customer is required to grant at no cost to LG&E such easements and rights-of-way on and across the customer's property that are reasonably necessary for LG&E to provide service to that customer.
- "Character of Service" is revised to permit LG&E at its discretion, when it is necessary to supplement its supply of natural gas with liquefied natural gas.

- "Gas Service Restriction" is revised to clarify that service restrictions to new or existing customers may be determined for portions of LG&E's gas system based on adequate system capacity or gas supply.

Q. Has LG&E made any other changes to its gas tariff?

A. Yes. LG&E has made a number of small edits to clarify certain issues and make clean-up edits throughout its gas tariff.

XIII. CONCLUSION

Q. What are your conclusions and recommendations?

A. Based on the evidence provided above and in the Companies' applications in these proceedings, I conclude the rates, revenue allocations, and proposed changes to the Companies' tariffs are reasonable and will aid the Companies in continuing to provide safe, reliable, and economical service to their customers. Therefore, I recommend the Commission approve the Companies' proposed rates, revenue allocations, and changes to their tariffs. I further recommend the Commission grant the Companies' requested CPCNs for AMI deployment and the related regulatory waivers.

Q. Does this conclude your testimony?

A. Yes, it does.

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 foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

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

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

July 11, 2022

APPENDIX A

Robert M. Conroy
Vice President, State Regulation and Rates
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3324

Previous Positions

Director, Rates	Feb 2008 – Feb 2016
Manager, Rates	April 2004 – Feb 2008
Manager, Generation Systems Planning	Feb. 2001 – April 2004
Group Leader, Generation Systems Planning	Feb. 2000 – Feb. 2001
Lead Planning Engineer	Oct. 1999 – Feb. 2000
Consulting System Planning Analyst	April 1996 – Oct. 1999
System Planning Analyst III & IV	Oct. 1992 - April 1996
System Planning Analyst II	Jan. 1991 - Oct. 1992
Electrical Engineer II	Jun. 1990 - Jan. 1991
Electrical Engineer I	Jun. 1987 - Jun. 1990

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995
Edison Electric Institute - Rates and Regulatory Affairs Committee
Southeastern Energy Exchange - Rates and Regulation Committee

Education

Essentials of Leadership, London Business School, 2004
Masters of Business Administration
Indiana University (Southeast campus), December 1998
Center for Creative Leadership, Foundations in Leadership program, 1998.
Bachelor of Science in Electrical Engineering;
Rose Hulman Institute of Technology, May 1987

Civic Activities

Olmstead Parks Conservancy – Board of Directors – 2016 – current
Leadership Kentucky – Class of 2016
Financial Research Institute – Advisory Board Member – 2016 – current

KENTUCKY UTILITIES COMPANY

CASE NO. 2020-00349

CALCULATION OF ECONOMIC RELIEF SURCREDIT - KENTUCKY RETAIL JURISDICTION

FROM JULY 1, 2021 TO JUNE 30, 2022

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE/ REFERENCE	ACCELERATION OF AMORTIZATION OF REGULATORY LIABILITY FOR REFINED COAL FACILITY REVENUES	ACCELERATION OF AMORTIZATION OF REGULATORY LIABILITY FOR UNPROTECTED EXCESS ADIT	TOTAL
1	AMOUNT OF REGULATORY LIABILITY TO BE RETURNED TO CUSTOMERS		$ (1,393,451)	$ (7,853,572)	$ (9,247,023)
2	GROSS-UP FACTOR USING 24.95% COMPOSITE TAX RATE (1/(1-24.95%))			1.33245	
3	TOTAL TO BE RETURNED TO CUSTOMERS	LINE 1 X LINE 2	$ (1,393,451)	$ (10,464,453)	$ (11,857,904)
4	ENERGY BILLING UNITS (FORECASTED TEST YEAR KWH)	SCHEDULE M-2.2			17,402,124,383
5	ENERGY SURCREDIT PER KWH	LINE 3 ÷ LINE 4			**$ (0.00068)**

KENTUCKY UTILITIES COMPANY

CASE NO. 2020-00349

CALCULATION OF ECONOMIC RELIEF SURCREDIT TRUE-UP - KENTUCKY RETAIL JURISDICTION

FROM JULY 1, 2021 TO JUNE 30, 2022

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE/ REFERENCE	ALL APPLICABLE RATE SCHEDULES
1	TOTAL RETURNED TO CUSTOMERS		$ -
2	LESS AMOUNT FORECASTED TO BE RETURNED TO CUSTOMERS	PG 1	$ (11,857,904)
3	TRUE-UP AMOUNT TO BE COLLECTED/(REFUNDED)	LINE 2 - LINE 1	$ -
4	ENERGY BILLING UNITS (FORECASTED TEST YEAR KWH FOR 15TH MONTH FOLLOWING APPROVAL)	SCHEDULE M SUPPORT	-
5	ENERGY TRUE-UP CHARGE/(CREDIT) PER KWH	LINE 3 ÷ LINE 4	**$ -**

CONFIDENTIAL INFORMATION REDACTED

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2020-00350

CALCULATION OF ECONOMIC RELIEF SURCREDIT - ELECTRIC OPERATIONS

FROM JULY 1, 2021 TO JUNE 30, 2022

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE/ REFERENCE	REGULATORY LIABILITY FOR TRANSFER OF TERRITORY TO MEADE COUNTY RECC	ACCELERATION OF AMORTIZATION OF REGULATORY LIABILITY FOR REFINED COAL FACILITY REVENUES	ACCELERATION OF AMORTIZATION OF REGULATORY LIABILITY FOR UNPROTECTED EXCESS ADIT	TOTAL
1	AMOUNT OF REGULATORY LIABILITY TO BE RETURNED TO CUSTOMERS		[redacted]			$ (33,981,214)
2	GROSS-UP FACTOR USING 24.95% COMPOSITE TAX RATE (1/(1-24.95%))				1.33245	
3	TOTAL TO BE RETURNED TO CUSTOMERS	LINE 1 x LINE 2	[redacted]			$ (38,888,324)
4	ENERGY BILLING UNITS (FORECASTED TEST YEAR KWH)	SCHEDULE M-2.2-E				11,352,592,560
5	ENERGY SURCREDIT PER KWH	LINE 3 ÷ LINE 4				**$ (0.00343)**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2020-00350

CALCULATION OF ECONOMIC RELIEF SURCREDIT TRUE-UP - ELECTRIC OPERATIONS

FROM JULY 1, 2021 TO JUNE 30, 2022

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE/ REFERENCE	ALL APPLICABLE RATE SCHEDULES	
1	TOTAL RETURNED TO CUSTOMERS		$	-
2	LESS AMOUNT FORECASTED TO BE RETURNED TO CUSTOMERS	PG 1	$	(38,888,324)
3	TRUE-UP AMOUNT TO BE COLLECTED/(REFUNDED)	LINE 2 - LINE 1	$	-
4	ENERGY BILLING UNITS (FORECASTED TEST YEAR KWH FOR 15TH MONTH FOLLOWING APPROVAL)	SCHEDULE M SUPPORT		-
5	ENERGY TRUE-UP CHARGE/(CREDIT) PER KWH	LINE 3 ÷ LINE 4	**$**	**-**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2020-00350

CALCULATION OF ECONOMIC RELIEF SURCREDIT - GAS OPERATIONS

FROM JULY 1, 2021 TO JUNE 30, 2022

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE/ REFERENCE		ACCELERATION OF AMORTIZATION OF REGULATORY LIABILITY FOR UNPROTECTED EXCESS ADIT
1	AMOUNT OF REGULATORY LIABILITY TO BE RETURNED TO CUSTOMERS		$	(2,029,005)
2	GROSS-UP FACTOR USING 24.95% COMPOSITE TAX RATE (1/(1-24.95%))			1.33245
3	TOTAL TO BE RETURNED TO CUSTOMERS	LINE 1 x LINE 2	$	(2,703,538)
4	GAS BILLING UNITS (FORECASTED TEST YEAR CCF)	SCHEDULE M-2.2-G		436,532,190
5	GAS SURCREDIT PER CCF	LINE 3 ÷ LINE 4	**$**	**(0.00619)**
6	GAS SURCREDIT PER MCF	LINE 3 ÷ LINE 4 x 10	**$**	**(0.0619)**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2020-00350

CALCULATION OF ECONOMIC RELIEF SURCREDIT TRUE-UP - GAS OPERATIONS

FROM JULY 1, 2021 TO JUNE 30, 2022

LINE NO.	DESCRIPTION	SUPPORTING SCHEDULE/ REFERENCE	ALL APPLICABLE RATE SCHEDULES	
1	TOTAL RETURNED TO CUSTOMERS		$	-
2	LESS AMOUNT FORECASTED TO BE RETURNED TO CUSTOMERS	PG 1	$	(2,703,538)
3	TRUE-UP AMOUNT TO BE COLLECTED/(REFUNDED)	LINE 2 - LINE 1	$	-
4	GAS BILLING UNITS (FORECASTED TEST YEAR CCF FOR 15TH MONTH FOLLOWING APPROVAL)	SCHEDULE M SUPPORT		-
5	GAS TRUE-UP CHARGE/(CREDIT) PER CCF	LINE 3 ÷ LINE 4	**$**	**-**
6	GAS TRUE-UP CHARGE/(CREDIT) PER MCF	LINE 3 ÷ LINE 4 x 10	**$**	**-**