BCUC 2012 Generic Cost of Capital

Dr. Lawrence Booth Undertaking No. 1

Hearing Date: December 21, 2012

Transcript Reference: Volume 8, Page 1567, Lines 10-17**.**

Requestor: G. Fulton, Q.C.

Question: Please provide a copy of the 2010 special comment by Moody's that you referred to in IR 50.1 of C6-15.

Response: The requested report is attached. The specific quote Dr. Booth references in IR 50.1 of C6-15 is on page 3.

MOODY'S
INVESTORS SERVICE

SPECIAL COMMENT

Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality

Evaluating a Utility's Ability to Recover Costs and Earn Returns

Table of Contents:

Analyst Contacts:

NEW YORK 1.212.553.1653

Michael G. Haggarty 1.212.553.7172
Senior Vice President
Michael.Haggarty@moodys.com
Joseph Vinciguerra 1.212.553.4137
Associate Analyst
Joseph.Vinciguerra@moodys.com
William L. Hess 1.212.553.3837
Team Managing Director
William.Hess@moodys.com

» Analyst contacts continued on the last page

Summary

A utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings. In Moody's Regulated Electric and Gas Utilities Rating Methodology, published in August 2009 (the Rating Methodology), these concepts are incorporated as the second of four key factors utilized to determine credit ratings in the regulated utility sector. The criteria we consider when analyzing this factor include the statutory and regulatory provisions in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery of costs, precluding any possibility of legal challenges to rate increases or cost recovery mechanisms. Such strong statutory protections are most often found in very supportive and protected regulatory environments like Japan and Hong Kong, for example. In the U.S., however, the ability to recover costs and earn returns is much less certain and can be subject to intense public and sometimes political scrutiny, and such provisions vary among state jurisdictions. Consequently, the analysis of a U.S. based utility's cost recovery and return provisions is more complicated. This Special Comment discusses the criteria we use to determine how a utility is scored in the cost recovery and return factor in our ratings methodology.

One of the most referenced, but potentially misleading, indicators used to judge whether a particular utility is recovering its costs and earning an adequate return is its regulatory allowed return on equity. Although a high allowed return on equity can be associated with a higher earned return, this measure cannot be looked at in isolation but must be viewed in relation to a utility's cost recovery provisions that impact actual earned rate of return, like automatic adjustment clauses, the length of rate cases, and the degree of regulatory lag that may occur. Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risk of a utility, providing justification for a relatively low allowed rate of return. We believe this is one of several reasons why both allowed and requested ROE's have trended downward over the last two decades.

Moody's views automatic adjustment clauses, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk. Fuel adjustment clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. Many of these clauses are annual but they can also be semiannual, quarterly, or monthly. The scope of automatic adjustment clauses has expanded over the years and now covers costs as diverse as transmission, generation, renewable energy, environmental compliance, pensions and bad debt. Generally, the more of these clauses a utility has in place, the stronger its scoring should be on this ratings factor and the lower the credit risk.

Other considerations when analyzing cost recovery include the test year used, regulatory pre-approvals, and the inclusion of construction work in progress (CWIP) in rate base. Forward test years are generally better predictors of future utility conditions than historical test years, and their usage is more likely to reduce regulatory lag. Regulatory pre-approval of major capital expenditures, especially for large, complex projects like new nuclear plants, are also important in the maintenance of utility credit quality. Similarly, the inclusion of CWIP in rate base provides greater regulatory certainty, reduces the chance of rate shock or regulatory disallowance at the end of the construction period, and helps moderate financial pressure on a utility during a capital build cycle. Some of these concepts require a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service.

Other cost recovery related factors Moody's considers to be favorable to utility credit quality include granting of interim rate relief, which we view as an effective way to accelerate the lengthy and cumbersome rate case process, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. Decoupling mechanisms to "de-link" utility revenues and profits from volumes are essential to credit quality if energy efficiency and demand side management programs become more prevalent in the sector as anticipated. Finally, the option to issue cost recovery bonds to securitize large or unexpected costs, like those from storms, is another way that a utility can recover its costs and avoid the rate shock that could result if such costs are passed on to ratepayers over a limited time frame.

Introduction

In Moody's Rating Methodology, the cost recovery provisions a utility has in place, as well as the return it earns, are important determinants of a utility's rating and overall credit quality. These concepts are incorporated into the ratings methodology as the second of four key factors we use to determine ratings in the regulated electric and gas utility sector. A utility's ability to recover its costs and earn a return represents a significant 25% of the overall weighting[1] of the factors used to determine a utility's credit rating. Unlike Factor 1, Regulatory Framework, which considers the general regulatory environment under which a utility operates and the overall position of a utility within that regulatory environment, Factor 2 addresses in a more specific manner the ability of an individual utility to recover its costs and earn a fair return on invested capital.

[1] The factor weightings shown in the rating methodology grid are approximate. The actual weight given to a factor in our assessment of an issuer's credit quality may differ based on the issuer's circumstances, and the scoring does not include every consideration that determines a rating.

TABLE 1

Regulated Electric and Gas Utility Rating Methodology

KEY RATING FACTORS AND WEIGHTINGS
1. Regulatory Framework – 25%
2. Ability to Recover Costs and Earn Returns – 25%
3. Diversification – 10%
4. Financial Strength and Liquidity – 40%

The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated electric and gas utilities, especially since the lack of timely recovery of costs has caused severe financial stress for utilities on several occasions. In five of the seven major investor owned utility defaults in the United States over the last 50 years, regulatory disputes culminating in insufficient or delayed rate relief for the recovery of costs and/or capital investments ultimately led to financial pressure and credit rating downgrades. The reluctance to provide rate relief in some cases reflected regulatory commission concerns about the impact of large rate increases on customers as well as concerns about the appropriateness and prudency of the relief being sought by a utility. Currently, given the utility industry's sizable capital expenditure requirements for infrastructure needs and environmental compliance, there is likely to be a growing and ongoing need for rate relief to recover these expenditures, at a time when economic conditions may limit the ability or willingness of regulators to provide this timely rate relief. Regulators also need to balance the amount of rate relief granted to utilities with consumers' ability to absorb these costs.

For regulated utilities, the criteria we consider in assessing Factor 2 include the statutory protections in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan and Hong Kong, for example.

More typically, however, and as is characteristic of most utilities in the U.S. and elsewhere in Asia, the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost adjustment clauses or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score in the A category for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa score for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

Most of the utilities in Central and Eastern Europe (CEE) inherited oversized, outdated and underinvested infrastructure, built during previous communist regimes. Furthermore, those infrastructure assets are very often highly depreciated. Therefore, the main regulatory challenges for the CEE region lies rather in the area of full recovery of investment costs, including the establishment of appropriate regulatory asset bases and the determination of reasonable regulatory depreciation levels (which would be included in allowable costs to be recovered), rather than fine-tuning the actual level of return. Indeed, there is a very similar issue confronting South Africa, where there has been a long period of underinvestment in electricity assets. The approach towards the determination of the regulated asset

base and treatment of asset revaluations differ significantly across the developing markets and could impact utilities' ability to generate sufficient funds for future investment in new assets.

The following is a discussion of the key factors we consider when scoring Factor 2, "Ability to Recover Cost and Earn Returns", in our Rating Methodology. The current Factor 2 scoring for the operating utilities in our rated universe is shown in Appendix A. These Factor 2 scores provide in indication of our current thinking. The scores are not intended to be static and continue to be monitored and modified as warranted to reflect changing conditions and circumstances, particularly as new rate cases are decided and cost recovery provisions evolve. In addition, when applied within the context of the Rating Methodology framework grid, the scores shown in Appendix A may be further modified by the use of a "strong" or "weak" designation.

Return on Equity and Regulatory Lag

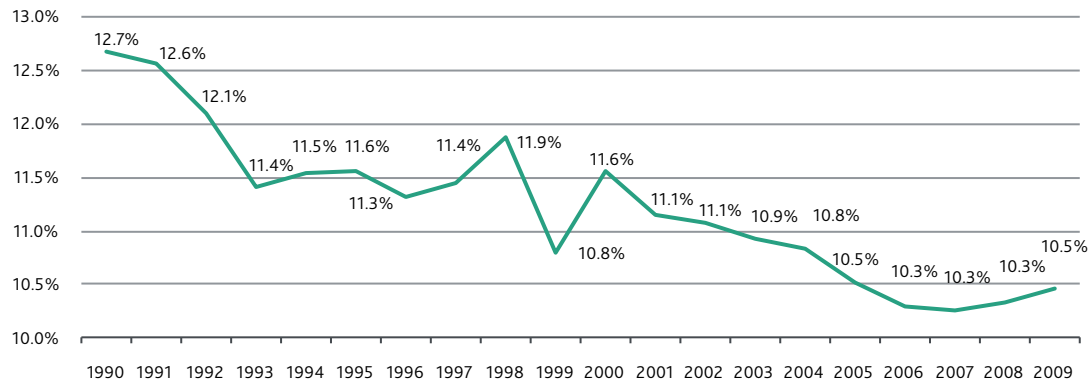
A utility's allowed return on equity (ROE) is one of the most obvious but potentially misleading statistics used to judge if a utility is recovering its costs and earning an adequate return. High ROE's are typically better than low ROE's, one reason that the timely, forward looking regulation of the Federal Energy Regulatory Commission (FERC) is viewed as more supportive, with ROE's that can be 12% or higher. In theory, if a utility's allowed return on equity is set at a high level, its earned return should also be high, leading to higher equity values, lower costs in relation to revenues, and ultimately higher credit ratings. This framework exists for some investor owned utilities, with high ROE's equating to good earnings and strong metrics, although this is not always the case. Earned ROE's are important in that they help to measure management's ability to operate their utility system within a given regulatory structure. A low allowed ROE is often associated with low earned ROE's, thereby affecting net income, lowering retained cash flow, depressing equity values, and raising financing costs.

However, the relationship between a utility's allowed return on equity and its ability to recover its costs and earn an adequate return is not as simple or clear cut as it may appear. A utility may have a low allowed ROE but be permitted to recover many of its operating costs through automatic adjustment clauses and other trackers, reducing risk and mitigating the impact of a low ROE. On the other hand, a utility may be permitted a high allowed ROE, but because of the higher than average risks associated with operating within this jurisdiction, the absence of such cost recovery provisions, overly long rate cases, or significant regulatory lag, may never actually earn its allowed return. According to the Edison Electric Institute, the average regulatory lag in the utilities industry is 11 months, close to where it has been for most of the last two decades. Adequate liquidity reserves on the part of utilities should mitigate some of the risks associated with regulatory lag.

While it is important to establish a link between a utility's regulatory allowed ROE and its automatic adjustment cost recovery clauses, it is also important to associate its authorized ROE with the sales forecast underlying the return. On its face, a high allowed ROE may appear favorable, although the return may be premised on a historic test year in which a high level of sales was achieved, which may not reoccur. This scenario could occur if there is a subsequent economic recession, unexpected financial shock, or lower usage on the part of the utility's customers due to high electric and/or gas rates or energy conservation. In such a case, a utility with a higher allowed ROE may be no better positioned than a utility with a lower allowed ROE based on a more achievable sales forecast. Allowed ROE's generate headline news, and market participants often gauge, at first blush, a utility's treatment in a rate case by this measure. However, the allowed ROE should not be viewed in isolation, but must be evaluated within the context of a utility's overall cost recovery provisions.

FIGURE 1

Average Awarded Electric ROE



Source: Regulatory Research Associates, a subsidiary of SNL Financial ,LLC, Edison Electric Institute

While regulatory lag has been stable, the long-term trend in allowed ROE's over the last two decades has been down, with the average allowed ROE falling from the 12% to 13% range in the early 1990's to the 10% to 10.5% range in recent years. In some cases, utility allowed ROE's have dropped below 10%. Not surprisingly, the average requested ROE has exhibited a similar trend, falling from as high as 13.5% in the early 1990's to approximately 11.2% in the first quarter of 2010. While some of the decrease in ROE's can be attributed to falling interest rates over the period, some can also be attributed to the other mechanisms that utilities have put in place to ensure timely cost recovery and maintain adequate returns, many of which are discussed below.

Some regulators view mechanisms such as cost recovery provisions and other automatic cost adjustment clauses as materially reducing the business and operating risk of some utilities, thereby justifying a lower return on equity. While there may be some merit to this argument, the relationship between these mechanisms and return on equity is complicated. Many of these provisions are "earnings neutral" but can have a cash impact, positive or negative, which could affect cash flow coverages and credit quality. Similarly, the increasing prevalence of formula based ratemaking and formula rate plans, where capital projects and other major revenue based changes are automatically incorporated into rates, have also caused some regulatory commissions to approve lower ROE's. However, a well structured formula rate plan could also lead to rate reductions if a utility is earning above its allowed range and in such cases, a lower allowed ROE may not be justified. Using ROE alone as a basis to compare utilities that operate under varying conditions and in different regulatory environments can be problematic and overly simplistic. Other considerations that may lead to widely different ROE's among utilities include the type of utility (whether vertically integrated or transmission and distribution), the mix of plants it operates, the size of its capital expenditure program, the risks associated with operating in a certain jurisdiction or building certain assets, demand and economic conditions within its service territory, and the utility's overall balance of debt and equity.

Fuel, Purchased Power and Other Automatic Cost Adjustment Clauses

Among the most common cost recovery provisions in the regulated utility sector are automatic adjustment clauses and other cost trackers (also referred to as riders or true-ups) for the recovery of

costs outside of traditional base rate cases. The most prevalent type of such clauses are fuel adjustment clauses (FAC's) in the electric sector and purchase gas adjustments (PGA's) in the gas sector. These generally permit automatic changes in rates in response to movements in the price of fuels used in the generation of electricity and in the price of purchased gas for local distribution companies. Moody's views automatic adjustment clauses as supportive of utility credit quality and important in reducing utility cash flow volatility and liquidity requirements. These clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. They also reduce the level of regulatory uncertainty for the recovery of these costs by ensuring, through regulatory or statutory means, their recovery up-front.

Important considerations when analyzing such clauses include the frequency of true-up calculations and the period of time over which revenue variances are recovered. For example, Consolidated Edison Company of New York's purchased power cost variances are calculated monthly and recovered or refunded generally within one or two months. Some gas LDC's have quarterly gas cost adjustments; some vertically integrated utilities calculate fuel variances annually and recover these costs the following year, while others may recover some costs over a longer time period. In general, more frequent variance calculations and shorter recovery periods are considered more supportive of credit quality, limiting the potential for the accumulation of large deferral balances, the recovery of which could result in rate shock for consumers, as well as liquidity and working capital stress.

Adjustment Clauses as Regulatory Policy

Fuel adjustment clauses became prevalent in the U.S. in the 1970's when dramatically higher oil prices severely affected the cash flows of several utilities, when the industry was much more reliant on oil as a source of fuel for generation than it is today. During this time, oil prices rose so quickly that traditional base rate proceedings, with their lengthy time schedules, were unable to address cost recovery in a timely manner, severely stressing the cash flows of several utilities. Since that time, most U.S. states have permitted their utilities to automatically adjust fuel related rates outside of a formal base rate proceeding. In Missouri, one of the few states that historically did not have a fuel adjustment clause, legislation was passed in 2005 permitting the Missouri Public Service Commission to implement such a clause. In Ohio, fuel recovery was recently granted to AEP's Ohio Power subsidiary, although Duke Energy Ohio has had one in place for years.

Volume risk and purchase cost adjustments emerged as important regulatory topics in Central and Eastern Europe (CEE) only after the increase in the volatility of energy prices and unprecedented declines of energy consumption caused by the recent recession. The approach of respective CEE regulatory bodies varied from strong opposition to timely adjustments, mostly motivated by social considerations (i.e. Poland, Slovakia), to incorporation of automatic fuel and purchase adjustment mechanisms into regulation. Surprisingly, the regulatory regimes of Baltic countries, where the recession took the greatest toll, showed relatively solid resilience to political interference and allowed the local dominant electric utilities (the Latvian Latvenergo and the Estonian Eesti Energia) to pass through costs from fluctuating fuel input prices, thus allowing them to generate sufficient cash flows even in times of significant economic readjustment; this justifies their scoring of A in this factor.

In Korea, KEPCO's financial performance suffered significant deterioration in 2008 as a result of exposure to contracted high fuel costs and sharp depreciation of the Korean Won. The government stepped in and approved a 4.5% tariff increase and a KRW668 billion one-off subsidy to offset its losses due to high fuel costs and currency devaluation. The government is also considering implementing an automatic cost pass through mechanism in due course.

Automatic adjustment clauses are typically aimed at mitigating the effects of highly variable costs, such as fuel and purchased power, which are typically the largest component of utility operating expenses. These costs have been particularly volatile over the last several years, a time when the industry has become more exposed to both natural gas and coal prices. This exposure was again highlighted in late 2005 when two major hurricanes severely disrupted natural gas production in the Gulf Coast region, leading to a sudden and sustained increase in natural gas prices. Such costs are for the most part out of the utility's control, although some try to manage them by hedging their fuel supply to some degree. However, both the magnitude and volatility of these costs make fuel adjustment clauses one of the more widely used and effective cost recovery mechanisms in the industry.

In some cases, fuel adjustment clauses may be limited in scope or subject to regulatory review to ensure that the costs that are incurred are prudent. Some states allow rate adjustments within certain ranges or bandwidths, with any costs incurred outside of these ranges deferred for recovery in subsequent base rate cases. Cost deferred and recovered through later base rate cases depress cash flow and inevitably add to regulatory lag, a short-term issue that should not negatively affect long-term credit quality

Fuel adjustment clauses, which also include purchased power costs, have also become critical to transmission and distribution utilities that no longer own generation assets following the deregulation of electricity markets in their states. Many of these companies are responsible for procuring power for their retail customers as part of their Provider of Last Resort or POLR obligations and, as a result, are responsible for procuring their generation requirements in the wholesale power markets. The lack of a prompt and timely generation cost adjustment clause or similar pass-through mechanism can have a detrimental effect on transmission and distribution utility cash flows and credit quality.

Automatic adjustment clauses and other pass-through mechanisms have been expanded over the years and now cover costs as diverse as transmission, new generation, renewable energy, environmental compliance costs, demand side management and energy efficiency costs, pensions, and bad debt expenses. These clauses may also be put in place for more unusual or extraordinary costs such as those incurred as a result of hurricanes or ice storms. In some states, changes in interest expense relative to what had been incorporated into existing rates have also been covered by such clauses. Like fuel and purchased power adjustment clauses, these other clauses are likely to increase the likelihood of timely recovery of prudently incurred costs, reduce regulatory uncertainty, and lead to a higher score for a utility's cost recovery factor in our ratings methodology.

Forecast Risk – Historical Versus Forward Test Years

In most utility ratemaking procedures, the selection of a test year is an important consideration in determining both the level of adjustments to rates that may be necessary later and the degree of regulatory lag the may result. A test year is the base year in which a forecast of a utility's operations and investment requirements over a twelve month period is devised. It is supposed to be representative of what costs will be incurred by a utility during an upcoming period, and establish what additional rate adjustments a utility will need to cover costs and earn an adequate rate of return. Depending on the regulatory provisions of a particular state, utilities are generally required to use either a historical test year or a future test year. In some cases, a combination or "hybrid" of these two test year periods can be used, with "known and measurable" adjustments.

A historical test year utilizes a twelve month period before the current rate filing as the basis for determining future rates. Some state regulatory commissions prefer historic tests years because the information used in determining rates is based on actual data that can be easily measured and analyzed.

However, in situations where industry conditions are changing rapidly, such as when costs are increasing or capital expenditures growing, historical test years are generally less useful as an accurate data point for setting future rates. In addition, the use of historical test years can contribute to regulatory lag in that a utility must usually file another rate case to recover those costs not accurately predicted with the use of the historical test year. As a result, utilities that use historical test years typically do not earn their allowed rate of return on an ongoing basis and experience persistent regulatory lag in the recovery of costs.

The use of a forward (or future) test year, while not a perfect predictor of future utility revenue requirements, strives to use the most timely and up-to-date information available in setting rates. Forward test years are typically based on forecasts of future costs and expenses, often leading to a high degree of scrutiny by regulators on the financial models and assumptions used in creating these forecasts. While all forecasts have limitations, forward test years are generally better predictors of future utility conditions than historical test years, especially where there are rapidly changing industry conditions. Forward test years can better incorporate current and expected economic conditions, a utility's capital expenditure budget going forward, and projected changes to a utility's customer base or load growth forecasts, for example. Moreover, forward test years help to reduce regulatory lag and ensure that a utility earns closer to its allowed rate of return. As a result, from a credit standpoint, Moody's views the use of forward test years as more supportive of utility credit quality than historical test years.

Regulatory Pre-Approvals

The utilities industry is in the midst of a substantial capital expenditure program, with significant investment planned in all aspects of its business, including generation, transmission, and distribution, as well as for substantial environmental compliance expenditures. Because of the size and complexity of many of these projects, Moody's places a high degree of emphasis on the regulatory certainty for the recovery of such costs, which is critical for the maintenance of utility credit quality. For some of these projects, especially when considering added uncertainty related to the economy and the timing of future laws and regulations related to carbon, it will be viewed as a significant credit positive if utilities are able to obtain regulatory support for recovery in advance. This would serve to limit regulatory risk associated with eventual disallowance or nonrecovery of already expended costs. Some U.S. states, including Idaho, Iowa, Virginia, and Wisconsin, have passed legislation pre-approving some generation costs and outlining cost recovery provisions for new plant construction, which Moody's considers to be a positive regulatory development for the utilities in those states. In India, the construction of Ultra Mega Power Projects do not have any cost recovery provisions, but are rather based on competitive tariff structures. Pre-approval of purchased power agreements would also be considered positively from a credit standpoint.

Approval of future project capital expenditures in advance requires a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service. In order for a state regulatory commission to pre-approve costs for a large and complex project, it is necessary for the commission and commission staff to gain an understanding of the project, including the need for the project, the construction budget, and the financing plan. Some projects underway right now, such as new nuclear construction, are expensive, complex, and multi-year in scope, and may not have been undertaken at all if regulators were not on board with the prudency of their projected costs and timetable in advance.

Regulatory pre-approval of utility capital expenditures may include incentives, mandated completion dates, or caps on the aggregate amount of recovery, giving state regulators some control over the ultimate costs and thus limiting ratepayer exposure in the event there are cost overruns or delays. In some cases, utilities may seek pre-approval for capital expenditures on a regular basis, such as annually or semi-annually, throughout the project's construction period. For example, for the recovery of costs related to Georgia Power's new nuclear construction project at its Vogtle plant site, the utility files a semi-annual construction monitoring report with the Georgia Public Service Commission (GPSC), with the GPSC reviewing and approving project costs on an ongoing basis. South Carolina Electric & Gas has a similar arrangement with the South Carolina Public Service Commission (SCPSC) for new nuclear construction at its Summer plant site. In order for such a pre-approval arrangement to be effective, however, state commissions need to have the time, ability, and resources to properly evaluate a complex project's construction progress, as well as any potential delays or problems that may arise. The Indiana Utility Regulatory Commission, for example, has an engineer advising them on Duke Indiana's Edwardsport project. Moody's views such collaborative utility-regulatory commission relationships as positive and important in insuring that prudent project costs are eventually recovered. They also serve to limit, but not fully protect against, the risk that there will be significant stranded, disallowed or otherwise unrecovered expenditures.

Construction Work in Progress (CWIP) in Rate Base/Concurrent Recovery

"Construction work in progress" (CWIP) represents the cost of capital projects that are under construction but not yet in service and considered "used-and-useful" in the provision of electric and/or gas service. Under traditional utility ratemaking, these costs cannot be included in customer rates until a project is completed and fully operational. However, because of the long lead times and large cost of many utility construction projects, some utilities are permitted by regulators to include CWIP in rate base, allowing it to earn a cash return on the project while it is under construction. The alternative would be for a utility to accumulate the financing costs on CWIP over the construction period (called "allowance for funds used during construction" or AFUDC) and include them in rates when the project is completed. Proponents of this approach generally argue that it is appropriate for utility ratepayers to pay only for projects that are in use and currently benefiting them through the provision of electricity and/or gas.

Moody's views the inclusion of CWIP in rate base as supportive of utility credit quality. It helps moderate the financial pressure of the incremental construction related debt by providing a cash return during lengthy, sometimes uncertain, and potentially delayed construction periods. It also allows a project's costs to be gradually incorporated into rates rather than all at once at the conclusion of construction, when a large and potentially unpopular one-time rate increase may be required. The resulting rate shock could lead to further delays in the recovery of these costs or political/legislative intervention aimed at limiting or denying utility cost recovery altogether.

It should be noted that not all CWIP recovery provisions are the same. Some state regulatory commissions only allow a portion of CWIP to be included in rate base, some only allow a debt return, while others allow a full weighted average cost of capital return. From a credit perspective, inclusion of all CWIP in rate base at a full weighted average cost of capital return would be considered the most supportive CWIP recovery provision.

Whether to allow CWIP in rate base became a significant issue several years ago, particularly during the last round of nuclear construction in the 1970's, when a number of utilities were engaged in major nuclear construction projects and substantial cost overruns were commonplace. This was also an era of

high inflation and high interest rates, exacerbating the rate impact of allowing CWIP in rate base. Because of this experience, a few states actually passed laws prohibiting utilities from including CWIP in rate base, some of which are still on the books today. The issue has again come to the forefront with the advent of major new nuclear construction in the U.S., and also because of large capital expenditure plans for transmission, renewable energy projects, integrated gasification combined-cycle (IGCC) plants, and environmental compliance requirements. Although the treatment of CWIP by individual state regulatory commissions varies, most states do allow for the inclusion of some or all of CWIP in rate base, a credit positive. Those states that do not allow the inclusion of CWIP in rate base, either by law or by recent commission decision, are listed below.

TABLE 2

States Not Allowing CWIP in Rate Base

LEGALLY PROHIBITED	DENIED BY COMMISSION
Connecticut	Arizona
Missouri	Nebraska
New Hampshire	Oklahoma
Oregon	Rhode Island
Pennsylvania	

The inclusion of CWIP in rate base is an especially important credit supportive measure for those utilities in the process of constructing new nuclear plants. In Georgia and Florida, for example, legislation passed over the last few years allows utilities in both states to earn a cash return on CWIP for new nuclear construction. For Georgia Power, the inclusion of CWIP in rate base and the recovery of financing costs on its new Vogtle nuclear construction project reduced the project's in-service cost to $4.5 billion from $6.4 billion. Similarly, in South Carolina, the Public Service Commission has authorized South Carolina Electric & Gas to earn a cash return on CWIP associated with new nuclear construction in that state. In contrast, in early 2009, Ameren subsidiary AmerenUE suspended efforts to build a new nuclear plant in Missouri after legislation allowing CWIP in rate base was not passed by the Missouri General Assembly.

As previously mentioned, the less favorable alternative to inclusion of CWIP in rate base from a credit standpoint is allowance for funds used during construction (AFUDC) accounting treatment for construction projects. With AFUDC, capital projects do not earn a cash return during the construction phase, but do when they become used and useful. Because of the long lead times and large cost of many utility construction projects, this can place great financial and liquidity pressure on utilities. Under AFUDC accounting conventions, a utility's earnings are made whole by non-cash earnings, offsetting the incremental debt and equity capital costs incurred to finance the projects. While there is no earnings impact on a utility income statement, cash flow generally lags while debt mounts, a credit negative. Some opponents to AFUDC treatment argue that rate payers generally face a larger one-time rate increase under this approach than if CWIP treatment was applied.

Interim Rate Relief

Because of the length of base rate cases, with many lasting 12 months and some as long as 18 months, interim rate relief is often an effective way to accelerate rate relief, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. While some states allow utilities to petition for interim

rate relief, others only permit such relief in extraordinary or emergency situations, limiting its use to unusually dire circumstances. Interim rate relief is also difficult for state regulators to grant when there are poor economic conditions in a utility's service territory, and some requests for interim rate relief are declined for these reasons. Because interim rate relief has a positive impact on utility cash flows and coverage metrics and reduces regulatory lag, Moody's views interim rate relief as a positive credit consideration. The existence of a maximum timeframe for decisions on interim (or general) rate cases is another important credit consideration. If there is no statutory time limit for rendering such rate case decisions, regulatory lag can result.

In Florida, utilities may request an interim rate increase only if they have petitioned the Florida Public Service Commission (FPSC) for a permanent base rate increase. In its most recent rate case, for example, Progress Energy Florida requested and was granted an interim rate increase to recover the costs of repowering one of its generating units to natural gas from oil. The interim rates were put in effect during the course of the base rate proceeding, which in Florida takes about nine months. Interim rates are credited back to customers, with interest, if the FPSC determines in its final rate decision that the interim rates were not justified. In Hawaii, interim rates must be enacted within 11 months of filing, but there is no statutory time limit for a final decision. As such, the majority of Hawaiian Electric rate decisions in recent years have been interim decisions.

In West Virginia, Appalachian Power and Wheeling Power, both subsidiaries of American Electric Power (AEP), requested an interim rate increase of $180 million in April 2009, out of an overall $442 million rate increase request, for fuel, purchased power, and environmental compliance project expenses. Because of sharply higher fuel costs, the company was paying more for fuel than it was receiving in existing rates and hoped the interim rates would offset a growing fuel underrecovery. On June 4, 2009, the Public Service Commission of West Virginia denied the request, citing the potential for financial hardship on customers, especially during currently difficult economic times. The denial of interim rate relief is considered a credit negative in that it added to fuel underrecoveries and increased regulatory lag at the utilities.

Volume Risk and Decoupling

There has been a great deal of emphasis and attention in recent years given to energy efficiency and demand side management programs aimed at reducing the consumption of electricity and natural gas both because of environmental concerns and for economic reasons. For utilities these efforts represent a potential threat to cost recovery because under traditional rate of return regulation, utility revenues are a function of the volume of power and energy is sold, i.e. all or a portion of the utility's fixed costs are recovered through volumetric charges. Consequently, utilities that are dependent on volume are, in fact, economically motivated to encourage higher energy usage instead of conservation and energy efficiency. Decoupling is aimed at "de-linking" a utility's revenues and profits from volume and at the same time compensating utilities for promoting less energy use.

Decoupling has become more prevalent over the last year since the Federal government's economic stimulus bill was passed in February 2009. That bill provides significant funding to states to promote and encourage energy efficiency programs, but only in the event there are incentives in place for utilities themselves to encourage and promote such programs. There are still relatively few states with decoupling measures in place for electric utilities, although they have been more common for gas utilities. Moody's views decoupling measures as important to the maintenance of utility credit quality in states where energy efficiency and demand side management programs could put pressure on utility sales volumes, operating margins, and cash flow coverage metrics.

TABLE 3

Selected States With Decoupling Measures in Place

ELECTRIC DECOUPLING	GAS DECOUPLING
California	Arkansas
Connecticut	California
Idaho	Colorado
Maryland	Illinois
Massachusetts	Indiana
Michigan	Maryland
New Hampshire	Massachusetts
New York	Michigan
Oregon	Minnesota
Vermont	New Jersey
	New York
	Nevada
	North Carolina
	Ohio
	Oregon
	Utah
	Virginia
	Washington
	Wisconsin
	Wyoming

The state of California was at the forefront of states adopting decoupling as far back as 1982, when it put an Electric Revenue Adjustment Mechanism in place, which de-linked utility revenues from utility sales to promote energy conservation. Other states have introduced decoupling more recently, including Idaho, Maryland, Massachusetts, and New York. Some states have partial decoupling measures in place, such as New Hampshire, which allows decoupling for generation and transmission, but not for distribution. Hawaii has recently approved a decoupling mechanism, which is most similar to the California model, but it has yet to be fully implemented into electric rates. Many more states are considering decoupling measures and Moody's expects such measures to become increasingly prevalent as energy efficiency and demand side management programs are increasingly emphasized.

Cost Recovery Bonds (Securitization)

Since the late 1990's, legislatively approved stranded cost, storm cost, and other cost recovery bonds have been issued to reimburse utilities for costs related to deregulation, hurricanes, environmental compliance, and energy supply. In its simplest form, a securitization is a type of irrevocable rate order that authorizes and dedicates a stream of cash flow to service bonds issued to reimburse utilities for specific costs. Such bonds were originally issued to compensate utilities for stranded costs following the deregulation of the energy markets in some states several years ago. More recently, storm-related securitizations have been completed following active hurricane seasons in 2004, 2005 and 2008 along

the Gulf Coast region and in Florida. Securitization bonds have also been issued to finance environmental compliance costs in West Virginia.

Cost recovery bonds represent another way that regulatory commissions and state legislatures can assure that a utility receives adequate recovery for sometimes large and unanticipated capital expenditures, while avoiding the rate shock that could result from passing through all these costs over a limited time frame. Instead, cost recovery bonds allow these costs to be spread out and financed over a multi-year period. Customers benefit from the low financing costs that characterize such bonds, since the special purpose entities issuing the bonds are typically rated Aaa, and the utility is reimbursed for the costs it incurred fairly quickly when the bonds are issued, reducing regulatory lag. However, Moody's notes that some storm cost recovery bonds have been issued as long as two to three years after the costs have been incurred, in some cases due to the need to pass legislation authorizing such bonds. Such legislation is necessary to insure that the collection of the cost recovery bond surcharge is statutorily protected, irrevocable, and non-bypassable. Moody's views utilities that have the option of issuing cost recovery bonds in the event of large, unexpected, or extraordinary costs more favorably from a credit point of view.

Conclusion

Cost recovery provisions and a utility's ability to earn an adequate return are important considerations in determining credit quality and credit ratings in the regulated utility sector, so much so that they account for a significant 25% weighting when determining utility credit ratings under our Rating Methodology. Among the provisions we consider when judging this factor include a utility's ability to earn its allowed return on equity, which must be examined in conjunction with its actual earned return on equity resulting from its overall cost recovery provisions. These provisions could include automatic adjustment clauses, the use of a forward test year, regulatory pre-approval of major capital expenditures, construction work in progress (CWIP) in rate base, interim rate relief, decoupling, and the option of issuing cost recovery or securitized bonds to recovery large or unexpected costs. The presence of most or all of these provisions is likely to lead to a higher score for the cost recovery and earned return factor in our ratings methodology.

Appendix A: Current Factor 2 Scoring for the operating utilities in Moody's rated universe

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
Tennessee Valley Authority	Chubu Electric Power Company, Incorp.	Alabama Power Company	ALLETE, Inc.	Companhia Energetica de Minas Gerais - CEMIG	Perusahaan Listrik Negara (P.T.)
	Chugoku Electric Power Company, Incorp.	Consumers Energy Company	Appalachian Power Company	Cemig Geracao e Transmissao S.A.	
	CLP Power Hong Kong Limited	Dayton Power & Light Company	Arizona Public Service Company	Companhia Paranaense de Energia - COPEL	
	Electric Power Delevopment Co., Ltd.	Detroit Edison Company (The)	Black Hills Power, Inc.	EDP – Energias do Brasil	
	Hokkaido Electric Power Company, Incorp.	Duke Energy Carolinas, LLC	Central Vermont Public Service Corp.	Empresas Publicas de Medelin E.S.P.	
	Hokuriku Electric Power Company	Duke Energy Indiana, Inc.	Cleco Power LLC	Entergy Texas	
	Kansai Electric Power Company, Incorp.	Florida Power & Light Company	Columbus Southern Power Company	Eskom Holdings Ltd	
	Kyushu Electric Power Company, Incorp.	FortisBC Inc	Duke Energy Kentucky, Inc.	Furnas Centrais Electricas S.A.	
	Okinawa Electric Power Company, Incorp.	Georgia Power Company	Duke Energy Ohio, Inc.	Israel Electric Corporation Limited (The)	
	Osaka Gas Co., Ltd.	Gulf Power Company	EDA - Electricidade dos Acores, S.A.	Light S.A.	
	Tokyo Electric Power Company, Incorp.	Indianapolis Power & Light Company	Eesti Energia AS	NTPC Limited	
	Tokyo Gas Co., Ltd.	Interstate Power & Light Company	El Paso Electric Company	Tata Power Company Limited (The)	
		Kentucky Utilities Co.	Empire District Electric Company (The)	Union Electric Company	
		Louisville Gas & Electric Company	Empresa de Electricidade da Madeira, S.A.		
		Madison Gas and Electric Company	Entergy Arkansas, Inc.		
		MidAmerican Energy Company	Entergy Gulf States Louisiana, LLC		
		Mississippi Power Company	Entergy Louisiana, LLC		
		Northern Indiana Public Service	Entergy Mississippi, Inc.		
		Northern States Power Company (Minnesota)	Entergy New Orleans, Inc.		
		Northern States Power Company (Wisconsin)	Hawaiian Electric Company, Inc.		
		Oklahoma Gas & Electric Company	Hydro-Québec		
		Pacific Gas & Electric Company	Idaho Power Company		
		Progress Energy Carolinas, Inc.	Indiana Michigan Power Company		
		Progress Energy Florida, Inc.	Kansas City Power & Light Company		
		Public Service Company of Colorado	Kentucky Power Company		
		South Carolina Electric & Gas Company	Korea Electric Power Corporation		
		Southern California Edison Company	Latvenergo		
		Southern Indiana Gas & Electric	Monongahela Power Company		
		Superior Water, Light and Power Company	Nevada Power Company		

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
		Tampa Electric Company	NorthWestern Corporation		
		Virginia Electric and Power Company	Ohio Power Company		
		Wisconsin Electric Power Company	Otter Tail Corporation		
		Wisconsin Power and Light Company	PacifiCorp		
		Wisconsin Public Service Corporation	Portland General Electric Company		
			Public Service Company of New Hampshire		
			Public Service Company of New Mexico		
			Public Service Company of Oklahoma		
			Puget Sound Energy, Inc.		
			Sierra Pacific Power Company		
			Southwestern Electric Power Company		
			Southwestern Public Service Company		
			Taiwan Power Company Limited		
			Tenaga Nasional Berhad		
			Tucson Electric Power Company		
			UNS Electric		

T&D Utilities

Aa	A	Baa	Ba	B
Hong Kong and China Gas Co. Ltd	AEP Texas Central Company	Atlantic City Electric Company	AES Eletropaulo	Edenor S.A.
Oman Power and Water Procur. Co.	AEP Texas North Company	Baltimore Gas and Electric Company	AES El Salvado Trust	
	CenterPoint Energy Houston Electric, LLC	Central Illinois Light Company	Bandeirante Energia S.A.	
	Central Hudson Gas & Electric Corporation	Central Illinois Public Service Company	Cemig Distribuicao S.A.	
	Central Maine Power Company	Cleveland Electric Illuminating Company (The)	Centrais Eletricas do Para S.A.	
	Consolidated Edison Company of New York, Inc.	Commonwealth Edison Company	Centrais Eletricas Matogrossenses S.A.	
	FortisAlberta Inc.	Connecticut Light and Power Company	Comp. de Ener. Eletr. do Est. do Tocantins	
	Hydro One Inc.	Delmarva Power & Light Company	Espirito Santo Centrais Eletricas - ESCELSA	
	Massachusetts Electric Company	Duquesne Light Company	Ejesa S.A.	
	New England Power Company	Illinois Power Company	Empresa Electrica de Guatemala, S.A.	
	Newfoundland Power Inc.	Jersey Central Power & Light Company	Energisa Paraíba-Dist. de Energia S.A.	
	Niagara Mohawk Power Corporation	Metropolitan Edison Company	Energisa Sergipe - Dist. de Energia S.A.	
	NSTAR Electric Company	Narragansett Electric Company	Gas Authority Inida Limited	
	Oncor Electric Delivery Company	New York State Electric and Gas Corporation	Light Serviços de Eletricidade S.A.	
	Orange and Rockland Utilities, Inc.	Ohio Edison Company	Perusahaan Gas Negara	
	Public Service Electric and Gas Company	PECO Energy Company	Rede Energia	
	San Diego Gas & Electric Company	Pennsylvania Electric Company	Rio Grande Energia S.A. - RGE	
		Pennsylvania Power Company	Towngas China Co. Ltd	
		Potomac Edison Company (The)	Xinao Gas Holdings Ltd	
		Potomac Electric Power Company		
		PPL Electric Utilities Corporation		
		Rochester Gas & Electric Corporation		
		Texas-New Mexico Power Company		
		Toledo Edison Company		
		United Illuminating Company		
		West Penn Power Company		
		Western Massachusetts Electric Company		

Transmission Only Utilities

A
American Transmission Company LLC
American Transmission Systems
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company
Trans-Allegheny Interstate Line Company

Local Gas Distribution Companies (LDCs)

Aa	A	Baa	Ba	B
Terasen Gas (Vancouver Island) Inc.	Atlanta Gas Light Company	Berkshire Gas Company	Gas Natural Ban S.A.	Camuzzi Gas Pampeana S.A.
	Bay State Gas Company	Boston Gas Company		Metrogas S.A.
	Brooklyn Union Gas Company, The	Cascade Natural Gas Corp.		
	Indiana Gas Company, Inc.	Cia de Gas de São Paulo - COMGAS		
	Michigan Consolidated Gas Company	Colonial Gas Company		
	New Jersey Natural Gas Company	Connecticut Natural Gas Corporation		
	Northwest Natural Gas Company	Laclede Gas Company		
	Piedmont Natural Gas Company, In	North Shore Gas Company		
	Public Service Co. of North Carolina, Inc.	Northern Illinois Gas Company		
	South Jersey Gas Company	Peoples Gas Light and Coke Co.		
	Southern California Gas Company	SEMCO Energy, Inc.		
	Terasen Gas Inc.	Source Gas LLC		
	Wisconsin Gas LLC	Southern Connecticut Gas Company		
		Southwest Gas Corporation		
		UGI Utilities, Inc.		
		UNS Gas		
		Washington Gas Light Company		
		Yankee Gas Services Company		

Moody's Related Research

Rating Methodology:

» Regulated Electric and Gas Utilities, August 2009 (118481)

Industry Outlook:

» U.S. Electric Utilities Face Challenges Beyond Near-Term, January 2010 (121717)

Special Comment:

» Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, June 2010 (125664)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

» contacts continued from page 1

Analyst Contacts:

NEW YORK 1.212.553.1653

Jim Hempstead 1.212.553.4318
Senior Vice President
James.Hempstead@moodys.com

A.J, Sabatelle 1.212.553.4136
Senior Vice President
Angelo.Sabatelle@moodys.com

Mihoko Manabe 1.212.553.1942
Vice President – Senior Credit Officer
Mihoko.Manabe@moodys.com

Allan McLean 1.416.214.3852
Vice President – Senior Credit Officer
Allan.McLean@moodys.com

Kevin Rose 1.212.553.0389
Vice President – Senior Analyst
Kevin.Rose@moodys.com

Laura Schumacher 1.212.553.3852
Vice President – Senior Analyst
Laura.Schumacher@moodys.com

Scott Solomon 1.212.553.4358
Vice President – Senior Analyst
Scott.Solomon@moodys.com

Natividad Martel 1.212.553.4561
Analyst
Natividad.Martel@moodys.com

Jim O'Shaughnessy 1.212.553.1607
Analyst
Jim.O'Shaughnessy@moodys.com

Wesley (Wes) Smyth 1.212.553.2733
Vice President – Senior Accounting Specialist
Wesley.Smythe@moodys.com

HONG KONG 1.852.3551.3077

Jennifer Wong 1.852.3758.1373
Assistant Vice President–Analyst
Jennifer.Wong@moodys.com

SAO PAULO 5511.3043.7300

Jose Soares 5511.3043.7339
Vice President-Senior Analyst
Jose.Soares@moodys.com

BUENOS AIRES 5411.4816.2332

Daniela Cuan EXT 141
Vice President-Senior Analyst
Daniela.Cuan@moodys.com

LONDON 4420.7772.5454

Helen Francis 4420.7772.5422
Vice President-Senior Credit Officer
Helen.Francis@moodys.com

TOKYO 81.3.5408.8100

Kenji Okamoto 81.3.5408.4219
Vice President- Senior Analyst
Kenji.Okamoto@moodys.com

Report Number: 122304

Author
Michael G. Haggarty

Associate Analyst
Joseph Vinciguerra

Senior Associate
John Grause

Production Associate
Sylviane Grant

MOODY'S
INVESTORS SERVICE