SIGNED AT AUSTIN, TEXAS the ______ day of February, 2016.

PUBLIC UTILITY COMMISSION OF TEXAS

____
DONNA L. NELSON, CHAIRMAN

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KENNETH W. ANDERSON, JR., COMMISSIONER

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BRANDY MARTY MARQUEZ, COMMISSIONER

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GULF STATES UTILITIES COMPANY, APPELLANT v. PUBLIC UTILITY COMMISSION OF TEXAS, ET AL., APPELLEES

No. 3-89-051-CV

COURT OF APPEALS OF TEXAS, Third District, Austin

784 S.W.2d 519*; *1990 Tex. App. LEXIS 403

January 17, 1990

SUBSEQUENT HISTORY: [**1] Rehearing Overruled February 28, 1990.

PRIOR HISTORY: FROM THE DISTRICT COURT OF TRAVIS COUNTY, 331ST JUDICIAL DISTRICT, NO. 444,066, HONORABLE MARY PEARL WILLIAMS, JUDGE PRESIDING.

COUNSEL: Mr. Barry Bishop, Clark, Thomas, Winters & Newton, Austin, Texas.

Honorable Jim Mattox, Attorney General, Honorable Susan D. Bergen, Assistant Attorney General, Ms. Barbara Day, Law Offices of Jim Boyle, Mr. John Laakso, Austin, Texas.

JUDGES: Before Powers, Carroll and Aboussie, J.J.

OPINION BY: POWERS

OPINION

[*519] In a statutory cause of action authorized by the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c, § 69 (Supp. 1989), Gulf States Utilities Company sued in district court for judicial review of a final order issued by the Public Utility Commission in a contested case. Texas Administrative Procedure and Texas [*520] Register Act (APTRA) *Tex. Rev. Civ. Stat. Ann. art. 6252-13a, § 19* (Supp. 1989). The district court declined to set aside the Commission order, and Gulf appeals to this Court. [1] *Id.* § 20. We will reverse the judgment and agency order, remanding the case to the Commission. *Id. § 19(e)*.

> 1 The final order results from the act of two commissioners who adopted portions of the hearing examiner's report, and the findings of fact and conclusions of law set out in that report. In some instances, the order substitutes other findings of fact and conclusions of law formulated by the two commissioners.
>
> The third commissioner dissented from the final order to the extent it limited Gulf to "avoided cost" in recovering in a rate proceeding any sums expended by it for power purchased from the joint venture.
>
> The Commission and the Office of Public Utility Counsel defend the Commission order on appeal.

[**2] THE CONTROVERSY

Gulf is a public utility that generates, distributes, and sells electric power under PURA and the Commission's regulation. Three of Gulf's largest electric-power customers, each situated in Louisiana, determined to withdraw from the Gulf system and to generate their own electric power. To minimize the resulting loss, Gulf proposed to the three customers that they and Gulf enter into a joint venture for the production of electric power. As a part of the undertaking, Gulf agreed to sell the joint venture two of Gulf's generating units, and to buy from the joint venture surplus electric power at a negotiated price specified in the contract. Gulf has owned and used the two generating units for a number of years. The power that Gulf promised to purchase from the joint venture would enter into Gulf's general power supply for sale and distribution to Gulf's remaining customers. The parties entered into a conditional contract on the terms indicated, and Gulf reported the transaction to the Commission as required by PURA § 63.

PURA 63

Section 63 of PURA requires public utilities to report to the Commission any sale of certain of their assets when the total consideration [**3] exceeds $ 100,000.00. On receiving a report, PURA § 63 directs the Commission to investigate the transaction, with or without a public hearing, to determine whether the sale "is consistent with the public interest," taking into consideration, among other things, the reasonable value of the property and facilities. If the Commission finds the transaction is *not* in the public interest, PURA § 63 commands that the agency: (1) consider the "effect of the transaction" in any ratemaking proceeding; and (2) disallow that "effect" if it "unreasonably" affects rates or service. PURA § 63.

Thus, a proceeding under PURA § 63 is not directed at obtaining the Commission's approval of a sale of utility assets, but it may affect a utility's rates if the Commission finds the sale is not in the public interest, and if it will unreasonably affect rates or service. A Gulf rate proceeding was pending in the Commission when it issued its final order under PURA § 63 in the proceeding we now review. [2]

2 In PURA § 37, the Legislature vested in the Commission "all authority and power of the State of Texas to insure compliance with the obligations of public utilities" set out in PURA:

For this purpose the [Commission] is empowered to fix and regulate rates of public utilities, including rules and regulations for determining the classification of customers and services and for determining the applicability of rates.

Unlike most actions by administrative agencies, the Commission's action in fixing the prices charged by a public utility, for its electricity, invokes eminent domain as opposed to police-power principles. The utility has, under the *14th Amendment to the Constitution of the United States*, a right to have its rates set at a level that is not "confiscatory" of its property. Phrased in another way, the utility has a right to a *fair and reasonable* return on the property it has devoted to the public service. This minimum return is also the minimum return intended by the Legislature in PURA § 39(a):

In fixing the rates of a public utility the [Commission] shall fix its overall revenues at a level which will permit such utility a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses.

On the other hand, PURA was enacted to prevent the charging of exorbitant rates through an abuse of monopoly power. Consequently, PURA § 38 instructs the Commission as follows:

It shall be the duty of the [Commission] to insure that every rate made, demanded, or received by any public utility . . . shall be *just and reasonable.*

(Emphasis added.) Thus, the Commission's ratefixing power operates exclusively within a range of reasonableness, bounded on the one hand by the utility's constitutional right to a fair and reasonable return, and on the other hand by its customers' statutory right to rates that are not unreasonable or exorbitant.

See generally Pond, *The Law Governing the Fixing of Public Utility Rates: A Response to Recent Judicial and Academic Misconceptions,* 41 Admin. L. Rev. 1, 28 - 30 (1989).

[**4] [*521] Section 63 of PURA does not provide as much, in explicit terms, but the Commission has necessarily construed the statute to permit the relevant inquiries before a sale of assets is consummated. The parties do not quarrel with that interpretation.

The Commission Order

After public hearings, the Commission determined that Gulf's sale of the generating units was generally in the public interest. The agency conditioned that finding, however, on two accounting requirements incorporated in the final order. Both refer to the manner of treating the transaction in Gulf's pending (and any future) rate proceeding. *First,* the Commission determined that it was not in the public interest for Gulf's Texas customers "to pay in excess of [Gulf's] avoided cost for purchased power from" the joint venture, and in any rate proceeding Gulf would be "limited to recovering those purchased power payments" that fell below Gulf's avoided costs. *Second,* the Commission determined that Gulf must treat as "other electric utility income" 83% of the sums Gulf receives from the joint venture in installment payments on the sale of the two generating units, and may treat as "non-utility [**5] income" the remaining 17% of such payments.

From these determinations, Gulf prosecuted its suit for judicial review of the Commission's final order. The trial court declined to reverse the order, and Gulf appealed. The parties join issue in this Court *solely* on whether the order should be reversed because the Commission erred in either of the two accounting measures imposed as conditions in the final order.

"AVOIDED COSTS" OF PURCHASED POWER

The Commission's decision to limit Gulf's recovery of operating expense to "avoided costs," in any Gulf rate proceeding, rests upon the Commission's interpretation of its rule found at 16 Tex. Admin. Code § 23.66 (1989). The ultimate issue on appeal, concerning "avoided costs," is the validity of the Commission's interpretation of that rule. That issue cannot be understood, however, except in reference to the matters next to be discussed, and the parties properly have devoted large parts of their briefs to them.

Public Utility Regulatory Policies Act of 1978

The joint venture has been designated a "qualifying facility" under federal statutory provisions and rules relating to "cogenerators" and "small power producers" of electric [**6] energy. These federal statutes and rules have the general purpose of promoting the development of alternative energy sources in an attempt to reduce the consumption of fossil fuels and to lessen our reliance on foreign energy supplies. [3] [*522] The federal statutory provisions were enacted as Pub. L. No. 95-617, 92 Stat. 3117 (1978) and given the name "Public Utility Regulatory Policies Act of 1978." The provisions were incorporated subsequently in various sections of 16

U.S.C. (1982 & Supp. 1989). *See generally* Miles, *Full-Avoided Cost Pricing Under the Public Utility Regulatory Policies Act: "Just and Reasonable" to Electric Consumers?, 69 Cornell L. Rev. 1267 (1984)*.

3 The encouragement of cogeneration and small-power production "has come from a requirement in the [federal Act, § 210] that electric utilities purchase power produced from such facilities at their full avoided costs . . . ." C. Phillips, *The Regulation of Public Utilities* at 442 (1988). The mandatory-purchase rule was aimed at removing one of the first of three obstacles that had prevented independent cogenerators and small-power producers from seeking to interconnect with an electric utility: "some utilities refused to purchase electrical power generated by such source or offered the cogenerator inadequate rates." Miles, *Full-Avoided Cost Pricing Under the Public Utility Regulatory Policies Act: "Just and Reasonable" to Electric Consumers?, 69 Cornell L. Rev. 1267, 1268 (1984)*. The author inferred this basis for the mandatory-purchase rule from various statements made in Congress in connection with the passage of the federal Act. These referred mainly to the utilities' fear that cogeneration and small-power production posed a threat of competition to the utilities' sales of electric power. *Id.* The remaining two obstacles consisted in the charging of discriminatory rates by the utilities for certain services, and in the effect of certain State and federal laws that subjected cogenerators and small-power producers "to plenary public utility regulation." *Id.* The calculation of "avoided cost" is not an easy matter. *See* Parmesano, "Avoided Cost Payments to Qualifying Facilities: Debate Goes On," Pub. Util. Fortnightly (September 17, 1987), at 34.

[**7] The Federal Energy Regulatory Commission administers the federal Act. Section 210(a) of the Act (*16 U.S.C.A. § 824a-3(a) (1985)*) requires the agency to prescribe "rules [that] *require* electric utilities to offer to . . . purchase electric energy from" qualifying cogenerators and small power producers. (Emphasis added.) Section 210(b) of the Act (*16 U.S.C.A. § 824a - 3(b) (1985)*) refers to the rates payable by electric utilities for such compulsory purchases of electric power: the rates must be just and reasonable to the utility's consumers and in the public interest; they may not be discriminatory against the qualifying cogenerator or small producer; and any rule prescribed by the agency may not "provide for a rate which *exceeds* the incremental cost to the electric utility of alternative electric energy." *Id.* (emphasis added). Section 210(d) (*16 U.S.C.A. § 824a - 3(d) (1985)*) defines "incremental cost of alternative electric energy:" the term means the utility's cost for "electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." *Id.* When orchestrated, these statutory [**8] provisions mandate that the Federal Energy Regulatory Commission prescribe rules that require electric utilities to buy electric power from "qualifying facilities," hether cogenerators or small-power producers, at a purchase price prescribed by the Commission that must be equal to or less than the cost the utility would incur by producing the power itself or buying the power from another source. Hence, the term "avoided costs" refers to the official price prescribed by the Federal Energy Regulatory Commission in such cases.

The Federal Energy Regulatory Commission promulgated the rules mandated by Congress. These govern when and under what conditions electric utilities must purchase electric power from "qualifying facilities." They also govern the setting of official prices for such sales, or the "avoided cost" rate to which the parties are bound by force of the federal Act. Neither the Act nor the federal rules purport to compel the utility and "qualifying facility" to contract for the official price and no other. Indeed, the Federal Energy Regulatory Commission "intended to permit utilities and qualifying facilities to negotiate rates *different* from those prescribed in the" [**9] regulations, which "were viewed as a buttress of protection for the qualifying facility in negotiations rather than as mandatory requirements to be enforced as to all transactions." Bruder & Simonds, "State Pricing Rules for Cogenerators and Small Power Producers--Eight Basic Issues," *Electric Power, Current Issues in Regulation and Financing* (Practicing Law Institute, 1982), at 300.

PURA § 41A

In PURA § 41A, the Legislature enacted somewhat analogous provisions dealing with transactions between electric utilities and qualifying cogenerators or small-power producers. The statute supplies a mechanism for certifying an electric utility's "avoided cost" in a particular transaction with a cogenerator or small power producer, the certified sum being included automatically in the utility's operating expenses for rate-calculation purposes in any rate proceeding that occurs while the certification is in effect.

Section 41A of PURA applies to agreements made between an electric utility and a "qualifying facility," as that term is defined [*523] in the federal Act to include certain cogenerators and small-power producers. *"If* an electric utility and a qualifying facility [**10] enter into an agreement providing for the purchase of capacity," either may submit a copy of it to the Public Utility Commission for "certification." PURA § 41A(b) (emphasis added). On receiving a copy for that purpose, the Commission must determine within 90 days (120 days if hearings are held) whether: (1) "the payments provided for in the agreement . . . are *equal to or less than* the utility's avoided costs"; and (2) the agreement contains sufficient assurances that the utility will be furnished a comparable supply of electricity in the event the qualifying facility ceases operation. PURA § 41A(d) (emphasis added). If both inquiries are answered affirmatively, the Commission must certify the agreement to be effective for 15 years unless sooner terminated by expiration of the agreement. While the certification remains in effect, the Commission is bound to "consider payments made under the agreement to be reasonable and necessary operating expenses of the electric utility," and must allow the utility "full, concurrent, and monthly recovery of the amount of the payments" required by the terms of the agreement. PURA § 41A(e) (emphasis added).

The introductory word "if" and the [**11] sense of PURA § 41A as a whole imply that the operation of the statute is conditioned upon an agreement of the kind described and its voluntary submission to the Commission by one of the parties for the certification process described in the statute. In context, the word "if" means "provided" or "in case that." *Bagnall v. Bagnall, 148 Tex. 423, 225 S.W.2d 401, 402 (1949).*

16 Tex. Admin. Code § 23.66 (1989)

In another part of PURA, the Legislature instructed the Commission to "make and enforce rules to encourage the economical production of electric energy by qualifying cogenerators and qualifying small power producers." PURA § 16(g). In that connection, we note that no Commission rule or order "shall be in conflict with the rulings of any federal regulatory body." PURA § 37.

The resulting Commission rule, found at 16 Tex. Admin. Code § 23.66 (1989), is entitled "Arrangements Between Qualifying Facilities and Electric Utilities." We have, in a footnote, set out those parts of § 23.66 that assist in its proper interpretation for the purposes of the present appeal. [4] The rule defines "avoided cost" in the same [*524] manner as the federal rule, § 23.66(a), and [**12] provides among other things that "rates for purchases of energy and capacity from any qualifying facility shall not exceed avoided costs," § 23.66(e)(2).

4 The rule found at 16 Tex. Admin. Code § 23.66 (1989) provides as follows after setting out various definitions of words and terms found in the rule:

* * * * * *

(b) Scope.

(1) Applicability. This subsection . . . applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(2) Negotiated rates or terms. Nothing in this subsection:

(A) shall limit the authority of any electric utility or any qualifying facility to agree to a *rate* for any purchase, or *terms* or *conditions* relating to any purchase, which differ from the rate or terms or conditions that would otherwise be required by this subsection; . . .

* * * * * *

(3) Filing of rates. All rates for sales to qualifying facilities, *contractual or otherwise,* shall be contained in the schedule of rates of the electric utility filed with the commission *in accordance with*

the Public Utility Regulatory Act.

(c) Availability of electric utility system cost data.

[Each utility must file with the Commission and maintain for public inspection specified "data" that relate to matters affecting its "interconnection" with qualifying facilities, including cost "data."]

(d) Electric utility obligations.

(1) Obligation to purchase from qualifying facilities.

(A) In accordance with subsections (e)-(h) of this section, each electric utility shall purchase *any* energy and capacity that is *made available* from a qualifying facility: [directly or indirectly].

(B) Each qualifying facility shall have the option of providing firm or nonfirm power.

(C) Each electric utility shall purchase energy and capacity from a qualifying facility with a design capacity of 100kw [kilowatts] or more within 90 days after the facility notifies the utility that it is a qualifying facility, provided that the electric utility has sufficient interconnection facilities available. . . . If an agreement to purchase energy and capacity is not reached within 90 days after the qualifying facility notifies the utility that it is a qualifying facility, the agreement, *if and when achieved,* shall bear a retroactive effective date for the purchase of energy (and capacity) correspondent [sic] with the 90th day following notice by the qualifying facility [of its status as such].

(D) Nothing in this rule shall be interpreted to require an [sic] utility to contract for capacity from qualifying facilities in excess of its capacity requirements, ...

(E) [The meaning of this subsection is quite obscure, owing no doubt to printing errors in the Texas Administrative Code. It appears to deal with incorporating purchases from qualifying facilities in a utility's long-term planning.]

(F) A utility shall purchase capacity from qualified facilities on the basis of evaluated cost and the quality of firmness of such capacity. . . .

(2) Obligation to sell to qualifying facilities. . . .

(3) Obligation to interconnect.

(A) Subject to paragraph (B) of this paragraph, any electric utility shall make such interconnections with any qualifying facility within its service area as may be necessary to accomplish purchases or sales under this section. . . .

(B) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under the Federal Power Act, Part II, ...

(4) Transmission to other electric utilities. . . .

(e) Rates for purchases from a qualifying facility.

(1) Rates for purchases of energy and capacity from any qualifying facility *shall be just and*

reasonable to the consumers of the electric utility and *in the public interest,* and shall not discriminate against qualifying cogeneration and small power production facilities.

(2) Rates for purchases of energy and capacity from *any qualifying facility shall not exceed avoided costs;* however, [when] the rates for purchase are based upon estimates of avoided costs over the specific term of the contract or their legally enforceable obligation, the rates for such purchases do not violate this subsection if the rates for such purchases differ from avoided costs at the time of delivery.

(3) Rates for purchases satisfy the requirements of paragraph (1) of this subsection if they equal avoided cost.

(4) Rates for purchases from qualifying facilities shall be in accordance with paragraph (1)-(3) of this subsection, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) Payments by a utility to any qualifying facility, if in accordance with paragraphs (1)-(3) of this subsection, shall be considered reasonable and necessary operating expenses of that utility.

(f) Standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. . . .

(g) Rates for purchases of nonfirm power from a qualifying facility. . . .

(h) Rates for purchases of firm power from a qualifying facility. . . .

(i) Periods during which purchases are not required.

(1) Any electrical utility which gives notice to each affected qualifying facility to cease delivery of energy or capacity to the electric utility will not be required to purchase electric energy or capacity during any period [when such purchases] will result in costs greater than [avoided costs], provided, however, this subsection *does not override contractual obligations of the electric utility to purchase from a qualifying facility.*

(j) Rates for sales to qualifying facilities.

(k) Interconnection costs.

(1) Interconnection plan. Each utility shall establish, and make available for inspection, guidelines for assuring safe and reliable operation of interconnected qualifying facilities. It may also require an interconnection plan from the qualifying facility to facilitate qualifying facility/utility negotiations. Upon receipt of the interconnection plan, the utility shall provide the qualifying facility with a cost proposal identifying the interconnection costs and *a list of contract issues to be addressed in negotiations.*

(2) Reimbursement of interconnection costs. Each qualifying facility shall be obligated to pay any interconnection costs. The utility's methods for determining and billing interconnection costs shall be consistent and shall be applied

on a nondiscriminating basis to all qualifying facility applicants for service.

(l) System emergencies.

* * * * *

(m) Enforcement. A proceeding to resolve a dispute between a utility and a qualifying facility arising under this section may be instituted by the filing of a petition with the commission. . . . The institution, conduct, and determination of the proceeding shall be in full accordance with the rules of practice and procedure of the commission.

16 Tex. Admin. Code § 23.66 (1989) (emphasis added).

[**13] While the present controversy comes to us solely as a proceeding under PURA § 63, we believe a proper construction of § 23.66 must account for PURA § 41A, to which the rule is most directly related, and [*525] the ratemaking provisions of PURA as well, primarily PURA §§ 37-41, 42, 43. We believe, as do the parties, that all of these rules bear upon the proper administration and interpretation of § 23.66, as it has been applied in this proceeding under PURA § 63. All of these statutory and rule provisions must be orchestrated and given a consistent and harmonious meaning insofar as they bear upon the same matters.

The Commission determined in its final order under PURA § 63 that the joint-venture transaction *was* consistent with the public interest. As an integral part of that determination, however, the Commission also fixed the effect the transaction would have in any proceeding in which Gulf's electric-power rates are established: Gulf may not recover, as a component of its "reasonable and necessary operating expenses" under PURA § 39(a), any sums paid the joint venture for electric power to the extent these payments exceed Gulf's "avoided costs." That is to say, [**14] in rate proceedings this component of Gulf's operating expenses will be limited to the sums Gulf saved by not producing the equivalent amount of power itself or purchasing it from a source other than the joint venture; and Gulf will be foreclosed from showing that any higher sums are "reasonable and necessary operating expenses" that Gulf would otherwise be entitled to recover by virtue of PURA § 39(a).

Gulf contends the Commission decision was arbitrary, capricious, an abuse of discretion, and affected by an error of law in this respect: the decision results solely from the Commission's erroneous conclusion that it was *bound* by its rule in 16 Tex. Admin. Code § 23.66 to limit Gulf to "avoided costs" *even if* Gulf shows in a rate proceeding that any higher sums paid the joint venture are "reasonable and necessary" under PURA § 39(a). Gulf argues that § 23.66, properly construed, mandates "avoided costs" only when an electric utility purchases electricity or capacity from a qualifying facility under the mandatory-purchase rule of 16 Tex. Admin. Code § 23.66(d)(1) (1989) which provides:

Obligation to purchase from qualifying facilities.

(A) In accordance with [**15] subsections (e)-(h) of this section, each electric utility shall purchase any energy and capacity that is made available from a qualifying facility: . . . .,

and when the parties contract to that end on the terms and conditions spelled out in § 23.66 for such cases.

The Commission and the Office of Public Utility Counsel reply in two basic contentions: (1) the Commission was free to interpret its own rule, denominated § 23.66, to encompass within its terms Gulf's purchases of electric energy from the joint venture, even though these purchases did not result from any obligation imposed upon Gulf by the mandatory-purchase requirement of § 23.66(d); and (2) the Commission's power to interpret § 23.66 in that fashion, to effectuate the public interest, was correct in light of the decision in *American Paper Inst., Inc. v. American Elec. Power Service Corp., 461 U.S. 402 (1983)*, where the Court held that the federal Act and regulations fixed avoided costs as the maximum rate unless the electric utility and qualifying facility agreed to a lower price.

In our view, the terms of § 23.66 provide for two kinds of contractual relations regarding sales and purchases [**16] of electric power between an electric utility and a qualifying facility. The rule makes the most detailed and explicit requirements when the contractual relations result from the mandatory-purchase requirements of § 23.66(d). Because these contracts are likely to be involuntary in their origin, the rule must and does prescribe the procedures to be followed in arriving at a contractual relationship and the basic rights and obligations of the parties: the electric utility must provide the public the "data" from which the utility's "avoided costs" and "interconnection costs" can be calculated, § 23.66(c); the utility's purchase obligations arise when the qualifying facility makes "available" any electric energy and capacity and "notifies" the utility accordingly, § 23.66(d)(1)(A), (C); the qualifying [*526] facility may elect to provide "firm or nonfirm" power, 23.66(d)(1)(B); the utility may not be required to purchase electric power in excess of its capacity requirements, § 23.66(d)(1)(D); the utility's purchases shall be "on the basis of evaluated cost and the quality of firmness," § 23.66(d)(1)(F); the utility must provide interconnection facilities on terms specified in [**17] the rule unless the utility would thereby become subject to regulation under the Federal Power Act, § 23.66(e); and so forth.

The rule also contemplates contractual relations established by terms and conditions *outside* the rule and its detailed provisions concerning the rights and obligations of the parties. This is plainly evident in § 23.66(b)(2)(A) where the rule declares that *nothing* in it "shall limit the authority" of either party "to agree to a *rate* . . . or *terms* or *conditions* . . . which differ from [those] that would otherwise be required by" the rule. (Emphasis added.) Contracts between the parties may be prompted originally by the mandatory-purchase requirements of the rule, but culminate in terms that vary from those specified in § 23.66. We imagine, moreover, that the parties may elect to include in their contract, in such instances, provisions much like those spelled out in the rule for cases where the parties cannot agree on their respective rights and obligations. The fact remains, however, that *the rule explicitly provides that the parties may contract on "terms" and "conditions" that differ from those prescribed in the rule.* More importantly, [**18] § 23.66(b)(2)(A) *also provides explicitly that the parties may contract for "a rate . . . which [differs] from the rate . . . that would otherwise be required by" the rule.* This provision, we believe, suggests the single reasonable meaning possible to be assigned § 23.66(e), the key provision in dispute in this appeal.

Subsection 23.66(e) governs the rates payable by an electric utility for its purchases from qualifying facilities. Indeed, it dictates what those rates shall be. Any interpretation of that subsection must *accommodate* the right of the parties to agree to a rate that differs from the rate that would otherwise be required by the rule -- a right explicitly recognized and preserved in § 23.66(b)(2)(A). With this basic principle of construction in mind, we quote in summary form the text of § 23.66(e):

(1) The rates charged a "qualifying facility shall be just and reasonable to the consumers of the electric utility and in the public interest, and shall not discriminate against qualifying" facilities.

(2) "Rates for purchases . . . from any qualifying facility shall not exceed avoided costs; . . . ."

(3) "Rates for purchases satisfy [**19] the requirements of [subsection 1] if they equal avoided cost."

(4) "Rates for purchases from qualifying facilities shall [conform to subsections] (1)-(3) . . . regardless of whether the electric utility . . . is simultaneously making sales to the qualifying facility."

(5) "Payments by a utility to any qualifying facility, if in accordance with [subsections] (1)-(3) . . ., shall be considered reasonable and necessary operating expenses of that utility."

We believe these provisions provide for the two eventualities possible to arise when an electric utility purchases electric power from a qualifying facility. *Firstly,* the parties may fail to agree on any rate, in which case the rate may not exceed "avoided cost" and, indeed, the rate is fixed to equal "avoided cost" simply by force of § 23.66(e)(2), (3). In such a case, the resulting rate automatically satisfies the requirement of subsection (1) that the rate be just and reasonable to consumers, in the public interest, and non-discriminatory against qualifying facilities. Consequently, the "avoided cost" rate may be certified *in a PURA § 41A proceeding* without further inquiry as to whether [**20] it is a reasonable and necessary operating expense. *Secondly,* the parties may agree to a rate that is more or less than "avoided cost," as § 23.66(b)(2)(A) explicitly permits them to do for reasons each regards as sufficient. In such a case, an independent inquiry [*527] must be made to determine if the rate is just and reasonable to consumers, in the public interest, and non-discriminatory against qualifying facilities, as subsection (1) requires.

Whether the rates are fixed by operation of the rule under the first eventuality, or whether they are fixed by the parties and the Commission finds they satisfy subsection § 23.66(e)(1), the resulting payments "shall be considered reasonable and necessary operating expenses" as directed in subsection (5) of § 23.66(e). If the agreed rate is lower than "avoided cost," however, it may be submitted for certification under PURA § 41A.

The foregoing is implied by the text of § 23.66(e), and the text itself rejects the Commission's interpretation. For example, the text cannot possibly contemplate a rate that is *always equal to or less than avoided cost,* because there would be in that case no need to specify in subsection (1) [**21] that the rate must be "just and reasonable" to consumers, in the public interest, and not discriminatory against qualifying facilities. The Commission's interpretation becomes positively unreasonable, however, when one considers that it renders entirely meaningless § 23.66(b)(2)(A), declaring that nothing in the rule limits the parties' authority to agree to a rate that differs from the rate "that would otherwise be required" *by the rule.* The meaning assigned by the Commission to § 23.66(e) *does* limit the parties' power to agree to another rate.

Section 23.66(e)(2) states quite explicitly that "rates for purchases of energy and capacity from any qualifying facility shall not exceed avoided costs . . . ." May the Commission therefore *construe* § 23.66(e) as setting the maximum rate that an electric utility may pay for electric power supplied by a qualifying facility, notwithstanding that this: (1) subverts the contracting parties' statutory right, under § 23.66(b)(2)(A), to agree to some other rate; and (2) renders superfluous § 23.66(e)(1) requiring rates that are just and reasonable, in the public interest, and non-discriminatory against qualifying facilities? The [**22] Commission and the Office of Public Utility Counsel contend the Commission was free to assign that meaning to § 23.66, notwithstanding the resulting anomalies, under the agency's general power to interpret its own rules. *Lloyd A. Fry Roofing Co. v. State, 541 S.W.2d 639, 544 (Tex. Civ. App. 1976 writ ref'd n.r.e.)* The Commission's power to interpret its own rules is obvious. [5] The issue is not the existence of the power but the validity of its exercise in this instance. Specifically, the issue is whether the Commission may by "interpretation" or "construction" *apply* [*528] *the rule to circumstances that are not included in the text of the rule by any reasonable inference from that text.*

5 An administrative agency has unquestionably the power to interpret its own rules, and its interpretation of its legislative rules is entitled to great weight and deference by a court called upon to interpret or apply such rules. *Lloyd A. Fry Roofing Co. v. State, 541 S.W.2d 639 (Tex. Civ. App. 1976, writ ref'd n.r.e.)*. Indeed, the Commission's interpretation of its rule becomes a part of the rule itself. *Sunset Express, Inc. v. Gulf, C. & S. F. Ry. Co., 154 S.W.2d 860 (Tex. Civ. App. 1941, writ ref'd)*. This does not mean, however, that on judicial review a court is bound absolutely to the *meaning* assigned by an agency to its rule. That idea is rejected by the very proposition that a court is obliged to give *deference* to the agency's interpretation, especially when the rule involves technical aspects or matters of administration peculiarly within the agency realm. The obligatory deference does not extend to agency interpretations that are plainly erroneous or inconsistent with the text of a rule. *United States v. Larionoff, 431 U.S. 864, 872 (1977)*. This exception exists for two basic reasons.

Firstly, "the courts must preserve the equal protection of the laws, even when those laws are administered by administrative boards." *Railroad Comm'n v. Shell Oil Co.,139 Tex. 66, 161 S.W.2d 1022, 1027-28 (Tex. 1942)*. An agency would exercise unbounded and unshackled discretion in applying its rule if it were free to assign the rule a meaning the text could not reasonably bear, and then apply that meaning to a party subject to the agency's power. Secondly, the courts must, when called upon in a proper case, restrain administrative agencies from exceeding their power. *Shell Oil Co., 161 S.W.2d at 1027-28*. An agency's power to prescribe rules to implement a statute extends only to carrying into effect the will of the Legislature as expressed in the statute. The agency may not, therefore, adopt a rule out of harmony with the statute. *Harrington v. Railroad Comm'n, 375 S.W.2d 892 (Tex. 1964)*. If the agency's interpretation of its rule places the rule out of harmony with the statute, of which the interpretation is an integral part, it is the court's duty to strike down the agency interpretation as ultra vires of the agency's powers.

[**23] We think it beyond doubt that the Commission intended its rule (§ 23.66) to have the *force and effect of law*. Indeed, the Commission's position in the case rests on that premise. The rule is denominated a "substantive rule" by the Commission, and the rule clearly affects individual rights or obligations to the extent it applies. It is therefore a "legislative" as opposed to an "interpretative" or "procedural" rule. *See generally General Electric Credit Corp. v. Smail, 584 S.W.2d 690 (Tex. 1979)*; *B-R Dredging Co. v. Rodriguez, 564 S.W.2d 693 (Tex. 1978)*; Schwartz, Administrative Law § 4.1.1, at 158-59 (1984); Davis,

Administrative Law Text § 4.6, at 126; 1 Cooper, State Administrative Law Ch. VII, at 175-76 (1965). As such, the *text* of the rule carries in and of itself an authoritative force *which binds* alike the *agency, affected persons, and the courts, just as a statute would do. See, e.g., Lewis v. Jacksonville Bldg. & Loan Ass'n, 540 S.W.2d 307, 310 (Tex. 1976)*; *Texarkana & Ft. S. Ry. Co. v. Houston Gas & Fuel Co., 121 Tex. 594, 51 S.W.2d 284, 287 (Tex. 1932)*. Consequently, the text of the rule must be construed under the same principles [**24] as if it were a statute. *Lewis, 540 S.W.2d at 310*. This does not mean, however, that the agency's *construction* of its rule invariably binds the courts. The agency's construction is controlling *"unless* it is plainly erroneous or inconsistent with the regulation" or rule. *United States v. Larionoff, 431 U.S. 864, 873 (1977)* (quoting *Bowles v. Seminole Rock & Sand Co., 325 U.S. 410 (1945))* (emphasis added). The exceptional circumstance applies in the present case where the Commission has unreasonably extended the scope of its rule beyond the limits of what the text reasonably permits.

We need not discuss that matter further, however, for it is obvious that the Commission's construction of its rule cannot stand for more fundamental reasons. Any construction placed by the Commission upon § 23.66 becomes a part of the rule itself. *Texarkana & Ft. S. Ry. Co., 51 S.W.2d at 287*. When the Commission's construction is engrafted upon § 23.66, the rule contradicts the clearly expressed intent of the Legislature in PURA § 39(a) (an electric-utility rate must permit recovery of "reasonable and necessary operating expenses"), PURA § 43(c) (the Commission may only [**25] disallow certain enumerated expenses of a utility and any other expenses that it *determines* are "unreasonable, unnecessary, or not in the public interest"), and PURA § 41A (if a utility and qualifying facility contract for a rate at or below avoided cost, they may have it certified by the Commission in which case the cost automatically constitutes "reasonable and necessary operating expenses" that the utility is entitled to recover monthly). The Commission's construction cannot stand because the validity of § 23.66 depends upon its being *in harmony with those statutory provisions and purposes. Texas Liquor Control Bd. v. Attic Club, Inc., 457 S.W.2d 41, 45 (1970)*. Section 23.66 falls out of harmony with those statutory provisions and purposes *if* the rule is construed to permit *only* a contract rate at or below "avoided cost," any difference being outside and irrelevant to the statutory methods and standards (PURA §§ 37-41, 42-43) prescribed by the legislature for the fixing of Gulf's rates. *See Railroad Comm'n v. Entex, Inc., 599 S.W.2d 292, 295-96 (Tex. 1980)* (rates may range only between maximum allowed by PURA § 40 and minimum fixed by PURA § 39). [**26]

We hold the Commission gave § 23.66(e) a construction that is unreasonable under the text of that provision and out of harmony with the pertinent statutory provisions and purposes. We must therefore reverse the agency order on the grounds claimed by Gulf: that the decision was arbitrary, capricious, an abuse of discretion, and affected by an error of law.

We should refer briefly to *American Paper,* upon which the Commission and the Office of Public Utility Counsel rely. The Court held in *American Paper* that the Federal Energy Regulatory Commission did not act arbitrarily or capriciously in promulgating a rule that set the contract rate at "full avoided cost," or "the maximum rate that the Commission *may prescribe."* [*529] *461 U.S. at 413* (emphasis added). The Court did *not* have before it a case where, as here, the *parties* contracted for a rate *higher* than the official rate prescribed by the

Commission. Thus, the decision furnishes no guidance in our consideration of the present case.

ALLOCATION OF FIXED-ASSET PAYMENTS

Gulf's contract with the joint venture required that the venture pay Gulf the purchase price of the two generating units in 20 [**27] annual installments of $ 6.35 million each. The aggregate of such payments, reduced in value to the time of the agency hearing, was about $ 51 million, a "gain" of $ 48 million over the $ 6 million net original cost of the two units. 6

6 The sale of a fixed asset ordinarily removes it, of course, from the utility's "rate base," or the aggregate of the net depreciated cost of all its assets "used and useful in rendering service to the public." PURA § 39(a). By thus reducing the "rate base," the sale automatically benefits the utility's customers because a "reasonable return" would not be payable on the asset and any operating and maintenance expenses associated with the asset would not be incurred after its removal from public service.

For one reason or another, the sale of the asset may bring a price in excess of the net depreciated cost at which it had been carried in the utility's accounts. The "net depreciated cost" is the remainder of the original cost of the asset after making deduction for the accumulated depreciation taken against it by the utility while it formed a component of the "rate base." *See* PURA § 41(a) (requiring that rates be based upon the original cost of property "less depreciation."). The accumulated depreciation taken against the original cost of an asset is the total of the sums charged against the asset periodically, as "operating expenses" under PURA § 39(a), while it was yet in the public service. *See* 16 Tex. Admin. Code § 23.21(b)(1)(B) (1989) (depreciation expense must ordinarily be based upon original cost and computed on a straight-line basis, however "other methods of nonaccelerated depreciation may be used for electric generating units when it is determined that such depreciation methodology is a more equitable means of recovering the cost of the plant.").

When the sale of an asset does bring a sum in excess of its net depreciated cost, the resulting "gain" may be claimed for the benefit of the utility's customers on a rationale that they have "paid" for the asset to the extent of the accumulated depreciation, because the sums taken as depreciation had the effect of elevating the utility's expenses and increasing thereby the rates paid by the customers. In other words, had depreciation not been taken, the utility's expenses would have been commensurately less, and the customers' rates lower to the same extent.

The foregoing rationale depends, of course, upon the grossest fiction in its premise that the ratepayers have "paid" for the asset. The literal effects are different:

The just compensation safeguarded to the utility by the 14th Amendment is a reasonable return on the value of the property used at the time that it is being used for the public service. And rates not sufficient to yield that return are confiscatory. Constitutional protection against confiscation does not depend on the source of the money used to purchase the property. It is enough that it is used to render the service. The customers are entitled to demand service and the company must comply. The company is entitled to just compensation and, to have the service, the customers must pay for it. The relation between the company and its customers is not that of partners, agent and principal, or trustee and beneficiary. The revenue paid by the customers for service belongs to the company. The amount, if any, remaining after paying taxes and operating expenses including the expense of depreciation is the company's compensation for the use of its property. . . .

Customers pay for service, not for the property used to render it. Their payments are not contributions to depreciation or other operating expenses or to capital of the company. By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience [nor any interest] in the funds of the company. Property paid for out of moneys received for service belongs to the company just as does that purchased out of proceeds of its bonds and stock. . . .

Bd. of Pub. Util. Comm'nrs v. New York Telephone Co., 271 U.S. 23, 31-32 (1926) (Citations omitted).

The fiction represents, nevertheless, a regulatory device for coping with the possibility that a utility might manipulate its affairs, accounts, and property in such a way that its customers are ultimately forced to pay rates that are actually more than "just and reasonable." This possibility is referred to in the text of our opinion. The fiction may also reflect, less persuasively, a naked *a priori* presumption in favor of ratepayers, as demonstrated in *Democratic Cent. Comm. v. Washington Metro. Area Transit Comm'n, 485 F.2d 786 (D.C. Cir. 1973). See* McCrea, *Awarding In-Service Appreciation to Public Utility Ratepayers--Windfall or Perdition?,* 11 Cal. W.L. Rev. 160 (1974).

We do not deal in the present case with the sale of non-depreciable property such as land. Consequently, our opinion should not be understood as referring to a transaction of that character.

[**28] The examiner recommended, and the Commission ordered, that Gulf's rate proceedings must account for a division of the annual payments in the following manner: [*530] 83% of such payments must be assigned to "other electric utility income," thereby reducing the sums necessary to be recovered from ratepayers in order to produce "overall revenues" sufficient to permit Gulf "a reasonable opportunity to earn a reasonable return on its invested capital . . . over and above its reasonable and necessary operating expenses," in the words of PURA § 39(a); and the remaining 17% may be assigned to "non-utility income" where it would not enter at all into the rate calculations required by PURA. [7]

7 In PURA § 41(c), the Legislature defined "net income"

to account for "all reasonable and necessary expenses" as determined by the Commission under rules laid down in the subsection. One such rule excluded "any expenditure found by the regulatory authority to be unreasonable, unnecessary, or not in the public interest . . . ." PURA § 41(c)(3)(D) Excluded expenses cannot enter the rate calculation and, in effect, must be borne by the utility. *Public Util. Comm'n v. Houston Lighting & Power Co., 748 S.W.2d 439, 441 (Tex. 1987).*

[**29] The foregoing division and allocation of the $ 48 million "gain" appear to constitute a departure from ordinary Commission requirements in accounting for "gains" on the sale of depreciable property that formerly constituted a part of the "rate base" because it was devoted to public service. The Commission's rules require regulated public utilities, such as Gulf, to keep a "uniform system of accounts as adopted and amended by the Federal Power Commission." 16 Tex. Admin. Code § 23.12(a)(2)(B)(i) (1989). Under this system of accounts, the $ 48 million evidently would have been assigned *in its entirety* to "non-utility income." *See 18 C.F.R. Part 101* at 351 (1989) (rules of the Federal Energy Regulatory Commission, to which certain regulatory functions of the Federal Power Commission were transferred in *42 U.S.C.A. § 7172 (1983)*); *see also, Washington Pub. Interest Org. v. Public Serv. Comm'n, 393 A.2d 71, 83 (D.C. 1978)*. But the federal rule requires such accounting treatment only in the ordinary case, that is to say, "unless otherwise authorized by the Commission . . . ." *18 C.F.R. Part 101* at 351 (1989). Because the Public Utility Commission expressly adopted the [**30] federal government's uniform system of accounts, we believe the Commission reserved the same flexibility: for rate-calculation purposes the uniform system of accounts should not bind the Commission absolutely when depreciable property is involved. *See, Washington Pub. Interest Org., 393 A.2d at 83.*

The assignment of 83% of the annual payments to "other utility income" results in a benefit to Gulf's ratepayers by reducing their required contribution (through rate payments) to the requisite level of "overall revenues" specified in PURA § 39(a)--a level that permits Gulf "a reasonable opportunity to earn a reasonable return on its invested capital" devoted to public service. Viewed from the ratepayers' standpoint, the inclusion of all the annual payments in "non-utility income" would result in their subsidizing Gulf's non-utility operations by their rate payments because those payments had been calculated in the past partly on the basis of a depreciation expense allowed Gulf on the two generating units. In a figurative sense, ratepayers "paid" for the two units in the past by their indirect contribution to Gulf's recovery of its depreciation expense.

Viewed from Gulf's standpoint, [**31] the Commission's order requires the company to subsidize its customers' purchase of electric power by unnaturally or artificially elevating the company's "other utility income," the "gain" on the sale of the two units being primarily the result of an increase in their market value due to economic "inflation."

The Commission justified assigning 83% of the annual payments to "other utility income" on a basis set out in a part of the hearing examiner's report expressly adopted by the agency, referring to the testimony of two witnesses. The part so adopted recites:

Dr. Andersen testified that because 83 percent of the original cost of these units [*531] had been recovered from the ratepayers, no less than 83 percent of any gain realized from the sale of these units should accrue to the ratepayers by booking 83 percent of the annual capital charge, (*i.e.* the fixed asset payment) above rather than below the line. (Entries above the line impact the ratepayers, while entries below the line do not.) Similarly, Mr. Bellon testified that because [Gulf] and the shareholders have recovered approximately 83 percent of the costs related to [the two units], the ratepayers should [**32] receive 83 percent of the fixed asset payment [Gulf] receives from the sale of the units. In addition, Dr. Andersen recommended that the remaining 17 percent of gain be split evenly between [Gulf's] ratepayers and shareholders, with the ratepayers' portion being booked above the line.

Gulf contends the 83% - 17% division and allocation for rate purposes is arbitrary, capricious, an abuse of discretion, at odds with established legal principles, and unsupported by substantial evidence.

Gulf thus raises one of the more complicated issues in public-utility law: when and to what extent may a regulatory body, as a condition to some favorable action requested of it by a regulated utility, extract from the utility a share of the "gain" over original cost that the utility has realized in the sale of a fixed asset formerly included in the rate base, the extracted sum being applied to the benefit of ratepayers in the form of lower rates? *See generally* McCrea, *Awarding In-service Appreciation to Public Utility Ratepayers--Windfall or Perdition?* 11 Cal. W.L. Rev. 160 (1974). The Commission's finding that the sale of the two units was in the public interest is [**33] not challenged by anyone. The parties dispute only the included conditions and findings relative to the accounting transactions that the "public-interest" finding incorporates and requires.

We believe the Commission had the general regulatory power to assign all or a part of the annual payments to either account for rate purposes, "other utility income" or "non-utility income." The question under discussion concerns the validity of the Commission's exercise of the power under the rate-calculation standards of PURA and the three methods designed to secure regulated utilities the return they are constitutionally entitled to receive: the comparable-earnings test, the financial-integrity test, and the attraction-of-capital test. These have remained the criteria for constitutionally sufficient rates from *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n, 262 U.S. 679 (1923)*, through *Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944)*. Pond, *The Law Governing the Fixing of Public Utility Rates: A Response to Recent Judicial and Academic Misconceptions,* 41 Admin. L. Rev. 1, 9-13 (1989). A rate that does not meet the requirement of these tests is [**34] "unjust, unreasonable and confiscatory" under the *14th Amendment of the United States Constitution*. Pond, *supra*, at 9 (quoting *Bluefield, 262 U.S. 679*). The rate-fixing provisions of PURA necessarily incorporate these constitutional considerations.

We believe the Court of Appeals of Kansas properly identified some of the factors to be considered by a regulatory body in deciding whether, and to what extent, utility ratepayers should benefit through lower rates from a utility's realized "gain" on the sale of depreciable fixed assets formerly included in the rate base. *Kansas Power & Light Co. v. State Corp. Comm'n, 5 Kan.App.2d 514, 620 P.2d 329 (Kan. App. 2d 1981)*. These factors have an obvious relevance to the three constitutional tests mentioned above, and to statutory requirements such as PURA § 38 that mandate "just and reasonable" rates. The Kansas court recognized the general proposition that such capital gains are ordinarily retained by the utility and used for reinvestment or the payment of dividends. *Id. at 341*. When the utility applies for a rate adjustment, however, the following factors should be considered in deciding a proper division and allocation [**35] of the gain, if any should be made at all:

(1) The risk of loss of investment capital.

[*532] (2) Contribution by the ratepayers to the value of the property, such as maintenance, upkeep and improvements.

(3) Financial integrity of the company, and the effect of the allocation on the price of the stock and the ability of the company to attract adequate capital.

(4) Increases in the value of the property due to inflation.

(5) Increased value of the property due to improvements in the neighborhood . . . as a result of special assessments for such things as curbing, guttering, sewage treatment plants, sewers, water, water treatment plants, general street facilities, neighborhood improvement districts, urban renewal, and other matters resulting in increased value of the property which were paid in whole or in part by the ratepayers.

The court pointed out that these were not intended to be "all inclusive." [8] We should think, therefore, that a regulatory body might consider *any* factor logically related to any of the three constitutional tests or to the determination of "just and reasonable" rates under a statutory provision such as PURA [**36] § 38.

8 We point out these factors only to demonstrate that a division and allocation of gain, from the sale of a utility's fixed asset, my invoke a variety of considerations, some of which might bear upon mere reasonableness or upon the constitutional tests that must be accounted for in arriving at a utility's rate. Not all will apply in every case, and unlisted factors may apply in another case. Decisions in these matters rest, of course, in the initial power of the Commission. It may determine, for example, that assigning all the gain to the benefit of the ratepayers, through lower rates in the future, will likely reduce the attraction of new capital that the utility requires.

In the present case, the record indicates that the Commission gave *no* consideration to *any* factor whatever before directing the 83% - 17% division based on the accumulated depreciation taken on the two generating units in years past, and made its decision solely on the fiction that the ratepayers had "paid" 83% of the original cost and assigned that percentage to "other utility income" on the recommendation of two witnesses that the Commission "should" take that action. *The mere fact that the ratepayers had "paid" 83% of the original cost, in past bears, does not automatically render "fair," "just" or "reasonable" the allocation ordered by the Commission in absolute terms for the purpose of governing future rate proceedings.* The issue is more complicated than that, as indicated in the decision of the Kansas Court of Appeals.
[**37]

In the present case, however, the Commission explicitly considered the issue and made its decision *solely* upon *one* basis: two witnesses testified that Gulf's ratepayers "should" receive the benefit of the sums realized by Gulf in the sale, in specified percentages, the Commission choosing 83% because Gulf had previously recovered through depreciation expense 83% of the original cost of the two generating units. From this, the Commission reasoned that ratepayers "should" benefit through diminished rates in the future--not by recovery of the total depreciation expense alone, but benefit as well to the extent of 83% of any sums over and above the total depreciation taken against the two units while they were in public service.

The Commission and the Office of Public Utility Counsel argue that the 83% determination is supported by "substantial evidence," referring, of course, to the testimony of the two witnesses concerning what decision the Commission "should" make in the matter. They point as well to the general rationale for assigning a portion of such gains to ratepayers, as stated by one of the witnesses:

[T]he Company's proposed disposition of the gain would create [**38] perverse incentives for a utility to liquidate the most valuable certificated [sic] property, thus leaving the regulated franchise as a haven for the automatic recovery of book costs associated with less productive plant.

Or, as better stated elsewhere:

If utilities have the right to charge ratepayers for expensive new generating plants, at cost, in the early years, when the power may not be economically competitive, and then sell off the asset to another entity once inflation makes the power cost-effective, and keep the profit for the stockholders, ratepayers are in an untenable bind. Every coal plant in the country built more than 5 years ago will [*533] change hands, as will all of the nuclear plants placed in operation prior to 1980, so that utilities can revise their rate base up to "replacement cost" or fair value.

T. Eisenberg, *Bankruptcy in the Administrative State,* 50 L. Contemp. Probs. 38 (1987).

These generalities are essentially meaningless in the present case as furnishing a reasonable evidentiary basis for the Commission's decision relative to the 83% - 17% division and allocation. The Commission explicitly determined [**39] that the sale of the two units was in the public interest in a case where it was not disputed that Gulf was moved to sell them because it was threatened with a loss of large industrial customers and a resulting adverse affect on its remaining ratepayers. Indeed, the Commission adopted the hearing examiner's findings that Gulf had "lost 430 MW [megawatts] of industrial electric load to cogeneration," that the customers who threatened to leave Gulf's service "have a total load of approximately 200 MW," and that they "will likely turn to self-generation if the Venture does not go forward." There is no finding, and no contention on appeal, that Gulf might have sold other generating units to the joint venture.

In substance, then, the Commission's final order, as supported by those parts of the examiner's report that the Commission expressly adopted, reflect only that the 83% - 17% division and allocation results from the opinion of two witnesses concerning what the Commission "should" do because of a general rationale that regulated utilities might otherwise sell their most efficient assets and reap the benefits, while retaining their least efficient assets to be subsidized by ratepayers. [**40] In other words, we are asked to determine that the *particular* division and allocation made here, with respect to *particular* assets, has a reasonable basis in the agency order and record when these contain only *generalities* about what the Commission "should" do to avoid abuses that are *not shown to be applicable* to the case under the agency's express findings.

It may be that the 83% - 17% division and allocation can be reasonably supported by existing administrative policies and the particular facts and circumstances of the case. We hold, however, that they are not reasonably supported by the agency order and record furnished us in this instance, and that the Commission determination is arbitrary and capricious as a result. We therefore reverse the Commission's final order and remand the case to the Commission.

For the reasons given, we reverse the Commission order and remand the case to th e agency. APTRA *§ 19(e)(4),(5),(6)*.

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MOODY'S
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RATING
METHODOLOGY

Regulated Electric and Gas Utilities

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

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

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

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

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

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

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

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

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

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

About the Rated Universe

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

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

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

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

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

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

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

4 We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply 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 six sections, which are summarized as follows:

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

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

Factor / Sub-Factor Weighting - Regulated Utilities

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

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

2. Measurement or Estimation of Factors in the Grid

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

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

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

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

3. Mapping Factors to the Rating Categories

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

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

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

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

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

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

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

Grid-Indicated Rating

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

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 asrates.

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.	

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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.

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

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

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

Factor 3: Diversification (10%)

Why It Matters

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

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

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

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

How We Assess Market Position for the Grid

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

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

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

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

How We Assess Generation and Fuel Diversity for the Grid

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

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

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

Factor 3: Diversification (10%)

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

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

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

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

Factor 4: Financial Strength (40%)

Why It Matters

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

How We Assess It for the Grid

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

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

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

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

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

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

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

CFO Pre-Working Capital / Debt

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

CFO Pre-Working Capital Minus Dividends / Debt

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

Debt/Capitalization

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

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

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

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

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

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

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

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

Factor 4: Financial Strength

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

Notching for Structural Subordination of Holding Companies

Why It Matters

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

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

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

How We Assess It

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

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

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

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

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

Strained liquidity at the HoldCo level

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

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

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

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

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

» Substantial diversity in cash flows from a variety of utility OpCos
» Meaningful dividends to HoldCo from unlevered utility OpCos
» Dependable, meaningful dividends to HoldCo from non-utility OpCos
» The group's investment program is primarily in strong utility businesses
» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

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

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

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

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

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

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

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

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

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

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

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

Other Rating Considerations

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

Liquidity and Access to Capital Markets

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

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

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

Management Quality and Financial Policy

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

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

Size – Natural Disasters, Customer Concentration and Construction Risks

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

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

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

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

Diversified Operations at the Utility

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

Event Risk

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

Corporate Governance

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

Investment and Acquisition Strategy

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

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

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

Financial Controls

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

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

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

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

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based 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 conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

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

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

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

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

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

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

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

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

Factor 3: Diversification (10%)

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

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

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

Factor 4: Financial Strength

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

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

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

General Approach to a Utility Family

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

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[16] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

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

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

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

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

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

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

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

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

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

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

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

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

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

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

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

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

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

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

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

Economic and Financial Market Conditions

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

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

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

Fuel Price Volatility and the Global Impact of Shale Gas

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

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

Distributed Generation Versus the Central Station Paradigm

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

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

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

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

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

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

Nuclear Issues

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

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

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

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance on notching corporate instrument ratings based on differences in security and priority of claim, including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

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

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

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

Securitization

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

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

lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

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

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

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

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

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

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

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

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

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

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

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

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

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

Additional considerations for PPAs

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

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

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

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

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

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

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

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

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

Methods for estimating a liability amount for PPAs

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

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

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

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

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

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

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

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

Moody's Related Research

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

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

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

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SPECIAL COMMENT

Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities

Evaluating a Utility's Regulatory Framework

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Summary

The framework in which a regulated utility operates is typically one of its most significant credit considerations. The regulatory structure and its general framework is a primary consideration that differentiates the industry from most other corporate sectors.

The characteristics of a utility's regulatory framework represents one of four factors that are considered, within the context of Moody's Regulated Electric and Gas Utilities Rating Methodology, published August 2009, (the Rating Methodology) to determine its rating. This Special Comment discusses our scoring criteria on that first factor.

A key consideration in our analysis is the degree to which a utility's regulator has the ability to independently regulate within the context of its legal, legislative or political environment.

We also examine how developed the utility's regulatory framework is; the decision making track record of its regulators; the utility's business model; and its regulators' openness to alternative rate mechanisms that help assure timely cost recovery.

We also evaluate patterns of regulatory contentiousness, which is often driven by political intervention at some level, in an effort to develop a view toward regulatory bias. This is one of the more challenging aspects to our analysis, since political intervention often occurs quickly and unexpectedly. Ultimately, we look to evaluate how the act of balancing a utility's appropriate cost of service and return on investment with consumer's ability and willingness to pay may change over time. Today's economic turmoil appears to be having some implications for this assessment in selected jurisdictions.

In the U.S., the vast majority of utilities operate within state regulatory frameworks that are reasonably transparent and well developed where regulators generally strive for a fair balance in establishing rates that assure reliable service at a reasonable cost to ratepayers while allowing a utility a fair opportunity to earn a reasonable return. However, assessing this balance is a complex procedure, and frequently involves a subjective assessment on our part. While most utilities in the U.S. score within the Baa range on the regulatory framework factor, indicating relatively solid support from a credit perspective – there are a few notable exceptions.

In Asia, with the exception of Hong Kong, Singapore and Japan, the regulatory framework is generally less transparent, and regulators may be under political pressure to reduce or maintain rates. In Europe, utilities that fall under the subject Rating Methodology, do so either because their regulatory and market development has taken place somewhat later than other countries within the EU[1], or because they are somewhat isolated and have received an exemption to the EU Electricity Directive. In Canada, the provincial regulatory frameworks are well developed, transparent and predictable, and most utilities score in the A range on the regulatory framework factor. In Latin America, regulatory frameworks vary with some being stable and transparent while other are constantly shifting and prone to political intervention.

It is important to note that our evaluation of a utility's regulatory framework is company specific, and that the score assigned for Factor 1 considers management's ability, over time, to cultivate supportive regulatory relationships.

Introduction

When evaluating the credit quality of a utility, the degree of support that it may depend on from its regulators is typically one of Moody's most significant considerations. The regulatory framework is also the prime factor in differentiating the industry from most other corporate sectors. This is partly due to the fact that a typical utility provides services that are essential to our way of life and to our economy, namely the delivery of electricity and/or natural gas. Utilities typically do not compete with other companies for the ability to provide these services, although some highly structured pockets of competitive retail "supply" of electricity have been introduced across the U.S. As a monopoly, the activities of a utility are usually conducted within a legislatively mandated oversight framework – where the national, provincial or state regulatory commissions - can review costs associated with the need to provide consistently safe and reliable service, plus provide a reasonable profit. Consequently, a utility's total, over-all revenue requirements and the rates associated with generating those revenues, are important considerations in evaluating this factor.

As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors.

In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly. Because of the regulatory safety net, defaults are rare in this sector, as compared with most industrial companies. However, there have been seven major investor owned utility defaults in the United States over the last 50 years, five of which resulted in Chapter 11 bankruptcy filings. In five of the defaults, a dispute with regulators regarding an insufficient or delayed response to a request for financial relief associated with the recovery of costs and/or capital investment in utility plant is generally cited as a primary driver that led to growing financial pressure, credit rating downgrades and, in most cases, the eventual filing for bankruptcy.

[1] The EU Electricity Directive of 1999 ("the Directive") ushered in a period of liberalisation of generation and supply prices and hence most European vertically integrated utilities are covered under the Unregulated Utility and Power Companies Methodology

In our Regulated Electric and Gas Utilities Ratings Methodology, published August 2009, (the Rating Methodology) the importance of regulatory influence is emphasized by the 50% weighting [2] ascribed to various statutory and regulatory provisions when determining a utility's credit quality. Factor 1, Regulatory Framework, the first of four key factors, is ascribed a 25% weighting and considers the general regulatory and political environment under which a utility operates and the overall business position of a utility within that regulatory environment. Factor 2, Ability to Recover Costs and Earn Returns, is also ascribed a 25% weighting and addresses in a more specific manner the ability of an individual utility to recover its costs and earn a fair return on invested capital.

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%

Factors 1 and 2 are inter-related in numerous ways. For example, whereas Factor 2 evaluates a company's specific success at earning returns and generating adequate, predictable cash flows, possibly as a result of its use of recovery mechanisms, such as those for fuel and purchased power, environmental, renewable or other expenses, Factor 1 considers, among other things, the regulator's demonstrated willingness to authorize a use of enhanced recovery mechanisms and to provide an ability for the company to earn adequate returns. This Special Comment discusses how we calculate a utility's score for Factor 1 - Regulatory Framework. (The current Factor 1 scoring for the operating utilities in our rated universe is shown in Appendix A). These Factor 1 scores provide an indication of our current thinking. The scores are not intended to be static; they continue to be monitored and modified as warranted to reflect changing conditions and circumstances. 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.

What are the characteristics of a utility's regulatory framework?

In evaluating a utility's regulatory framework, we consider such things as the regulatory body's independence; its legislative or political environment; the extent of the regulatory framework's development; its track record for predictable, stable decisions; the utility's business model; and the openness of the regulators to alternative rate mechanisms that tend to provide additional assurance of timely cost recovery and the ability to earn a return on invested capital.

Regulatory Independence

A key consideration in assessing Factor 1 is the degree to which the regulator has the ability to act as an unbiased arbiter over the facts in the record, and base its decisions on the existing laws and statutory decisions. Today, balancing the sometimes conflicting goals of assuring a reliable supply of reasonably priced electricity or natural gas; assuring the long-term financial health of the utilities it regulates; and authorizing rate increases within a given state or region is increasingly viewed as challenging.

[2] 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 grid does not include every consideration that determines a rating.

We look to see if the regulator consistently strives to achieve balance, between the investor and the consumer in assessing the utility's rate request, or substantially denies the rate request by acting perhaps in a manner more akin to a consumer advocate.

We also evaluate the impact of outside political influence on the regulatory process, where a legislature or a governor can revise, amend or restructure certain provisions associated with the traditional, vertically integrated electric utility framework. Political influence works in many ways, from utility sponsored legislation on the positive side to wholesale reductions to recovery on the negative side.

The majority of utilities in the rated universe of the Rating Methodology are considered to have average exposure to regulator independence, meaning their regulators generally try to take the middle path. There are a few notable exceptions, for example, in Indonesia, or in Argentina where the politicization of the regulatory relationship tends to be a dominant factor in assigning a score to the regulatory framework factor.

National and local regulation

When a utility's revenues are determined by a single national regulator, within a well developed and transparent framework, Moody's generally views the framework as being more independent, less susceptible to local political influence and more supportive of long-term utility credit quality than state regulation. The difference in risk reflects our view that national regulation tends to be more transparent and sometimes even formulaic, and less exposed to significant political or consumer intervention. This tendency is best exemplified in markets that are large, well developed, and relatively transparent; such as the U.K or Japan.

In smaller markets, national regulators may also be susceptible to local pressure, In Asia, each country has one regulator, but with the exception of Hong Kong, Singapore and Japan, the regulatory framework is generally less transparent, and in some countries, the regulators are under political pressure to maintain or reduce rates.[3] The economic recession of the past few years has also put pressure on national regulators in Central and Eastern Europe as well.

In Latin America, the regulatory frameworks vary from one country to another, in some countries, such as Chile, utility regulatory frameworks have been in place for an extended period, and are quite transparent; for others, such as in Argentina, the frameworks are constantly shifting and subject to political influence, while in Brazil the frameworks are more developed but still evolving. Federally regulated utilities in Argentina, which serve the most densely populated areas of the country, tend to be more subject to public scrutiny than the local, smaller utilities in the interior of the country. As a result, regionally regulated utilities have been favored by rate increases more often and in a more timely manner than federally regulated utilities.

In Canada, the provincial regulatory frameworks are well developed, transparent and predictable. In addition, Canadian utilities generally have not pursued diversification strategies and have limited exposure to unregulated activities at affiliates or holding companies. We view Canada's business and regulatory environments as being more supportive than many of those in the U.S. Accordingly, most utilities in Canada score in the A range on the regulatory framework factor.

[3] For example, there has been limited tariff increases in Indonesia for the past few years and Malaysia kept its rates unchanged from 1999 to 2006.

We would be likely to assign a score of Aaa or Aa for a utility's regulatory framework factor in jurisdictions where regulators are likely to take extraordinary action to support a failing company,[4] or where a utility can set rates independently, like the U.S. owned Tennessee Valley Authority. Additionally, U.S.-based transmission companies, which enjoy formulaic federally regulated rates determined by the Federal Energy Regulatory Commission (FERC), but do not see extraordinary supportive action from their regulator, are currently scored in the Aa range because of the transparent and predictable characteristics of that framework.

U.S. Transmission Regulation

In an effort to encourage investment in the aging U.S. transmission infrastructure, the FERC established a transparent and supportive approach to establishing rates for significant transmission projects. Elements of this approach include:

» Authorized returns on invested capital that are generally higher than those awarded by state regulators;

» An ability to earn a cash return on construction work in progress;

» An ability to recover abandonment costs;

» A significant equity component is allowed in capital structures and companies have the ability to utilize double-leverage;

» No rate hearings required to adjust rates;

» Rates reset annually via established formula, assuring timely recovery of actual costs and return on investment;

» The rate formula may be forward looking.

In our opinion, state-regulated investor-owned U.S. utilities carry higher regulatory risk than utilities with rates regulated entirely by FERC. The U.S. market is highly fragmented: many utilities are exposed to overlapping or unclear regulatory jurisdictions, and to volatile power prices. And since state regulation is far more local, it can become political - particularly when significant rate increases are proposed. Currently, all state regulated U.S. investor-owned utilities receive scores that range from "A" to "Ba" for the regulatory framework factor.

We also acknowledge that a utility's operations are subject to regulation on numerous fronts, including operational safety and environmental controls. In these cases, federally or nationally imposed regulation, that does not consider local conditions, may create additional uncertainty or may result in a disproportionate impact for individual utilities.

Political tendencies

When a utility's rate setting process is exposed to significant political interference, its rate-case outcomes become less predictable, often resulting in reduced expectations for cash flow stability, and in many instances introducing a long-term period of contentiousness. Utilities with a history of politically charged rate proceedings will tend to score in the ranges of either Ba or B on the regulatory framework factor. We have observed that while utilities may ultimately prevail through legal

4 This tends to be the case for utilities in Japan.

challenges, the process can take years to complete, and in most cases, the damage to credit quality will have already occurred.

In evaluating the potential for political interference in the U.S., we look beyond the method of commissioner selection (elected versus appointed). In our view, all regulation is political, so we do not differentiate in a significant manner how the commissioners got on the commission. In states where voters elect their regulatory commissioners, it might seem that consumer oriented political intervention - or a bias toward appearing to do everything possible to minimize rate increases, would be a heavy factor in rate case outcomes. In fact, while this is often the case, we have not found it to consistently be true.

Utilities in Arizona and New Mexico, where commissions are elected, have tended to experience protracted and highly publicized rate proceedings; as a result, utilities in these jurisdictions currently receive regulatory framework scores in the Ba range. Yet in numerous states with elected commissions such as Alabama, Georgia, North Dakota and South Dakota, utilities have not had a history of lengthy or politically charged rate proceedings. Many utilities in these states receive regulatory framework scores in the A range. It should be noted that a utility often represents one of the largest publicly-traded companies headquartered within a particular state that also employs a significant amount of the population with reasonably good jobs, is usually ascribed a substantial property tax bill and is often a very generous contributor to local charities.

On the other hand, the most significant recent examples of negative political intervention that posed a severe threat to utility credit has occurred within regulatory jurisdictions where commissioners were appointed, but their ability to act independently was impaired by the actions of politicians. We have seen this happen in recent years for utilities operating in Illinois and Maryland, which are now scored Ba on regulatory framework, but scored in the B range or lower amid threats of continued rate freezes or caps.

Utilities in California, which also has an appointed commission, faced extreme political opposition during the energy crisis of 2001-2002. Some of these utilities ultimately defaulted. This history is a key consideration in the score assigned to the regulatory framework for these companies; although for the past several years, the regulatory treatment for utilities in California has been among the more credit supportive observed for U.S. utilities, and until recently, their scores on Factor 1- Regulatory Framework remained within the Baa range. Currently, they are scored in the A category. In Florida, where the commission is appointed, utilities have historically experienced very supportive rate decisions, and those utilities had historically received scores in the A range. However, recent interventions by the Governor in the rate proceedings for Florida Power & Light and Progress Energy Florida - including the appointment of new commissioners in the midst of rate proceedings have contributed to our reassessment of this rating factor for these companies, resulting in lower regulatory framework scores for Factor 1 in the Baa range.

Outside of the U.S., utilities in Argentina provide a clear example of regulatory environments that are currently subject to a significant amount of political interference. Initially, ENARGAS was established as an independent agency to administer and enforce the Gas Act and applicable regulations for the gas distribution industry, including the tariff setting and periodic tariff review mechanisms. However, following the 2001-02 crisis, on July 2003 the Argentine government created a new agency (UNIREN or Agency to Renegotiate Public Utilities Contracts) to develop a common regulatory framework for all utilities and to renegotiate their tariffs. In addition, since May 2007 ENARGAS has been under an intervention decreed by the President, who appointed an official (or "Interventor") to be in charge of the agency. Therefore, many of the ENARGAS' technical duties are subject to political interference and as a consequence the regulatory framework is not transparent and highly unpredictable. As an example, Metrogas, an Argentine regulated LDC, has not been able to adjust its tariffs in over ten years, which has lead to a severe deterioration of the company's economic and financial situation. On June 17, 2010, the company filed for reorganization under Argentine law.

In some instances, political or legislative actions can, in fact, be supportive of utility credit quality – putting forth additional rate mechanisms or tools for state commissions to consider, or legislating specific time frames for rate decisions. Such actions generally offer the opportunity for a utility to receive more supportive treatment from its regulators, but they generally also require regulatory follow-through; and are typically not intended to impede the regulator's ability to balance the utility's need to recover its costs and earn a return with the desire to maintain reasonable rates. As a result, credit supportive legislative actions are generally less likely to immediately affect a utility's Regulatory Framework score.

Some political interventions have hurt utilities' credit quality

» When Illinois was preparing to fully transition to electric market rates for generation in 2006 and 2007, several bills were proposed that would re-freeze the electric rates for the state's primary utilities that had just come off a 10-year rate freeze. The bill's legislative progress caused considerable rate uncertainty – particularly since the regulator, the Illinois Commerce Commission, had already sanctioned power supply auctions for power procurement and approved rate phase-in plans. We considered the significant potential impact on utility cash flow as a major threat to credit quality which ultimately resulted in ratings downgrades to below investment grade for each of the Illinois transmission and distribution companies.

An August 2007 settlement avoided a more severe negative impact on the utilities' rates and credit ratings, and more recent regulatory proceedings have been concluded without direct political interference. However, this experience suggests the future possibility of political or consumer backlash if significant rate increases become necessary again . Moreover, the utilities' continued relationship with unregulated generation affiliates remains unchanged which was a primary motivation, in Moody's opinion, for the political pushback to transitioning to market rates for generation.

» Maryland also experienced a significantly politicized regulatory environment in 2006-2008 as its move towards electric retail competition became a major legislative and gubernatorial issue and was exacerbated by a potential acquisition of Constellation's Baltimore Gas & Electric Company (BG&E) utility subsidiary by Florida based FPL Group. New legislation produced significant uncertainty regarding electric utilities' ability to recover their increased costs for fuel and purchased power which ultimately resulted in significant deferrals and required refunds. Importantly, this legislation was passed after the Maryland Public Service Commission (MPSC) had already approved a plan that provided a more moderate deferral of rate increases. The legislature also voted to replace the full slate of MPSC commissioners - a highly unusual event.

During this time, the ratings of BG&E were downgraded by a total of three notches and remain at that level today. A spring 2008 settlement led to legislation that essentially resolved all issues; but not without a significant sustained reduction in BG&E's expected cash flow credit metrics. This relatively recent past experience, leads us to believe future political intervention cannot be entirely ruled out.

… while others have been supportive

» In Georgia, South Carolina and Florida, legislation has been enacted that permits utilities to earn a cash return on construction work in progress on nuclear plants. Moody's views this type of legislation positively as the resulting mechanisms provide support for a utility cash flows and credit metrics while significant construction is underway, and they also tend to reduce the potential for future rate shock.

» Michigan passed legislation in 2008 designed to reduce rate lag and encourage utility investment. In its 2009 and 2010 implementation of the legislation, the Michigan Public Service Commission appeared, in our opinion, to apply the legislation as intended; however, they also appeared to carefully balance the utilities' cost recovery needs with a need to minimize rate increases in a struggling economy. Such legislation has been a primary factor in the financial performance of the state's investor-owned utilities, given the severe economic contraction throughout the state.

Level of Development of the Regulatory Framework

Utilities that are operating within regulatory frameworks that are not well defined, or are relatively new, such as Eskom Holdings in South Africa, Israel Electric Corporation in Israel, Empresa Electrica de Guatemala S.A in Guatemala, and PLN in Indonesia will tend to receive lower regulatory framework scores, since a lack of development and track record reduces the level of predictability of rating outcomes and cash flow.

In Argentina, although a reasonable regulatory framework was established during the 1990's, and worked relatively well for almost 10 years, it was followed by a period of constant change of rules with very little support for the utilities' cost recovery requirements. In fact, for the past ten years, the majority of companies have been operating with frozen tariffs while costs continue to escalate. As a result of this high level of regulatory uncertainty and political intervention in the rate setting mechanism, the regulatory framework score for Factor 1 for all utilities in Argentina is in the B range.

Utilities in Brazil operate under a regulatory model that is well developed but with a relatively limited track record. The framework was implemented in 2004, and has generally evolved in a manner that has been supportive of utility investment and credit quality. Structural enhancements have included more efficient methods of power procurement, expansion of the national grid, centralization of long term energy planning, and increased thermoelectric capacity. Recognizing these improvements, in 2008 the regulatory framework score improved to Ba from B. However, the federal regulator is not fully independent of political pressure, and currently there is a fair amount of uncertainty surrounding the potential renewal or revocation of some utility concessions. As a result, the Factor 1 score for utilities in Brazil remains in the Ba range.

In certain instances, a utility's regulatory framework score could be tempered by the uncertain effects of policy changes (such as a transition to competition), or the implementation of new laws. As discussed above, Michigan in 2008 passed legislation enabling the Public Service Commission to give above-average support to its utilities - something which has proven to be beneficial in the current economic downturn. Even so, the improved regulatory environment is still relatively new and our concern about the sustainability of utility support in a continued weak economy holds Michigan utilities' regulatory framework scores in the Baa range.

Turnover among state regulatory commissioners may also increase the uncertainty surrounding rate case decisions. New commissioners often face challenges in quickly coming up to speed on complicated rate issues and obviously lack an established track record. Turnover that results from political intervention in opposition to rate increases, as we recently saw in Florida, is highly likely to have a negative impact on a utility's regulatory framework score.

Considerations within European Markets

The European utilities that fall under the Regulated Electric and Gas Utilities Rating Methodology, do so either because their regulatory and market development has taken place somewhat later than other countries within the EU or where they exist within isolated regimes where significant competition would be hard to achieve (such as the Portuguese regions of Azores and Madeira)[5] and hence have received an exemption to the Directive.

The regulatory frameworks that have been implemented in Central and East European (CEE) countries tend on the one hand to have benefited in the first place from the adaptation, albeit with some modifications, of the already well-established UK regulatory framework. However as the CEE utility markets have been historically rather fragmented, with varying speeds of liberalisation, the full application of a well defined, transparent and consistent regulatory mechanism does vary from region to region. The common factor affecting our evaluation of regulatory regimes in CEE is their short track record compared to the more established regulatory regimes in Western Europe.

In addition, the economic recession of the past two years, revealed a greater-than-expected political influence over the decisions of regulatory bodies even in the more developed CEE countries such as Poland or Slovakia. The adverse economic impacts of the recession raised the political pressures on regulatory regimes not only in the regions with historically highly politically-influenced regulation such as in South East Europe, but also resulted in increasingly politically and socially motivated decisions of historically more consistent and transparent regulatory regimes in Central Europe. Whilst certain regulatory decisions, such as the price cap established by the Slovak regulatory office across most of the regulated sectors or the reluctance of the Polish regulator to adjust tariffs during gas price hikes, have to be seen in the context of the extreme commodity price volatility recorded over the 2008-09 period, it appears that the independence of CEE regulatory regimes from political influence is still fragile and together with short track records prevents a high score on Factor 1.

Predictability and Stability

Utilities accustomed to fairly stable and predictable rate-proceeding outcomes tend to receive higher regulatory framework scores. This is heavily linked to the degree of a regulator's independence and how developed its framework is, but for utilities whose scores are not dominated by these factors, regulatory treatment over time may be a differentiating factor.

Regulation affects utility credit quality most directly by establishing prices (rates) for the electricity, gas and related services that the utility provides (revenue requirements), and by determining the authorized return on a utility's investment, as well as the authorized return to shareholders. In evaluating a utility's regulatory framework, we consider whether it has consistently been given rate increases that provides it an opportunity to recover its expenses and actually earn a rate of return in line with shareholder expectations.

Requested and authorized rates of return (ROEs) have trended downward over the last two decades, from about 12-13% in the early 1990s to the 10%-10.5% range more recently. Much of the decrease has stemmed from falling interest rates, but some of the decline may be attributed to other mechanisms put in place to ensure timely recovery and reduce risk (see next section). In evaluating the

[5] In this instance, they are subject to well-established Portuguese regulation under Entidade Reguladora dos Serviços Energéticos, where we apply a Baa to the Regulatory Framework

predictability of cash flows, we are concerned less with the awarded ROE, which has a tendency to become a headline, than the overall collective rate outcome, including the authorized base rate increase, the impact of any approved enhanced recovery mechanisms such as riders or trackers, and the implications for future cash flows. We observe that the amount of regulatory lag can be a contributing factor to a utility not being able to earn their authorized rate of return. From a credit perspective, while we are also less concerned with shareholder returns, we do observe that those companies that earn at or near their authorized rate of return tend to produce more predictable cash flows; and those companies that are not able to earn their authorized return tend to produce relatively weaker cash flow credit metrics.

The past two years have seen a tremendous amount of electric rate case activity, with rate increases generally coming in at slightly more than 50% of the requested amount. In prior years, when there was less activity, awards tended to be closer to 40%. Gas rate case awards, which have tended to be less politically contentious, have come in more consistently around 50%. While history tells us it is unlikely a utility would be awarded the full amount of its requested increase, companies that manage their regulatory relationships in a way that allows them to consistently achieve awards that provide an opportunity to earn a fair rate of return, would be more likely to receive an above average regulatory framework factor score.

Utilities that have received unwelcome surprises from regulators, with awards significantly lower than anticipated or less than enough to generally maintain or improve credit metrics, are likely to have a lower regulatory framework score. For example, the outlook of Consolidated Edison Company of New York (CECONY) was revised to negative and its ratings were ultimately downgraded following a change in our view of CECONY's historical relationship with its regulator and the extent to which we could expect future rate actions to be supportive of credit quality. In 2008, CECONY received a rate increase that was only about 35% of its requested amount, premised on a 9.1% ROE, which was significantly below the average ROE of 10% or so that was then typical for transmission and distribution utilities in other regulatory environments.

Alternative Rate Making Mechanisms

Another key aspect of a utility's regulatory framework is the regulator's openness to policies that could ease rate lag. Such policies could include the tendency for its rate cases to be settled rather than litigated over a protracted period, the use of interim rates and/or forward test years.

Other mechanisms are designed to assure cost recovery and give utilities the chance to earn allowed rates of return. These include such things as, pre-approval of recovery of investments for new generation, transmission or distribution; the inclusion of construction work in progress (CWIP) in utility rate bases; the existence of attrition revenues which provide cash returns on construction expenditures, the inclusion of riders or trackers for specific investments or expenses; and the design and administration of mechanisms that allow the recovery of prudently incurred costs for fuel and purchased power.

Where rate design reduces or eliminates the utility's exposure to fluctuations in gas or electricity consumption that can be caused by weather, economic conditions, gas or power costs or legislative or regulatory conservation requirements, the utility is likely to enjoy more stable revenue and cash flow than would otherwise be the case. This form of rate design, known as decoupling, tends to lower a utility's business risk and could contribute to higher scoring on Factor 1.

Although the impact of these factors on any given utility is considered more specifically when assigning scores to the second of the four factors utilized to determine utility credit quality, the ability to recover costs and earn returns, and as described more fully in Moody's Special Comment on Cost Recovery Provisions dated June 2010, to the extent these mechanisms have been a consistent part of the regulatory framework for some time it would also be considered positively when assigning a score to the regulatory framework factor.

A Utility's Business Model Could Affect Regulatory Framework Score

In evaluating the regulatory framework we also consider a utility's business model and its impact on its relationship with its regulators. We consider the amount and type of unregulated activity that a company may be engaged in as well as the nature of its regulated operations.

For utilities with some unregulated operations, we will look at the competitive and business position of these unregulated operations. Moody's views unregulated operations that have minimal or limited competition, large market shares, and statutorily protected monopoly positions as having substantially less risk than those with smaller market shares or in highly competitive environments. Those businesses with the latter characteristics usually face a higher likelihood of losing customers, revenues, or market share. For utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be the case if the utility had solely regulated operations.

We also consider the degree to which a utility might be indirectly exposed to unregulated business risks by virtue of the ownership of such businesses by affiliates or parent holding companies. We will consider the tendency of parent companies to pursue diversification strategies which, in the absence of effective ring-fencing mechanisms, could expose the regulated utility to increased financial risk. Historically, holding company diversification into unregulated, and sometimes unrelated, business lines and into international markets has had generally negative credit consequences for regulated utility subsidiaries.

We also evaluate the nature of the utility's regulated businesses. Local Gas Distribution Companies sometimes referred to as LDCs, are generally considered to have lower business risk than electric utilities. These utilities tend to almost universally have mechanisms in place that pass the commodity cost of gas directly to their customers, tend to have capital expenditure plans that are more consistent than electric utilities, reducing the need for large sudden rate increases; and tend to have less contentious issues with their regulators. Decoupling, a concept designed to protect a utility from the risk of declining usage, has become more prevalent in recent years as regulators have sought to encourage energy efficiency, and is currently much more prevalent in gas utilities. Therefore, LDCs could receive higher scores on the regulatory framework factor than electric utilities operating within the same jurisdiction.

In jurisdictions that have deregulated power generation activities, utilities have been left with only a delivery obligation, giving them - in theory - a lower business risk profile as they are not exposed to the costs and operating risks associated with power production. However, in many deregulated markets, the utility maintains a provider of last resort (POLR) obligation, and may be subject to rate caps or freezes that do not always allow the full timely recovery of costs for power purchased or hedged to meet their POLR obligations. A utility that provides only transmission and distribution services, and truly has no exposure to retail customers, is viewed as having a lower business risk profile and its regulatory framework would likely score above average. This is true for the majority of the transmission and distribution utilities operating in Texas, the Factor 1 scores for these companies are in the A range. Conversely, utilities with significant POLR and under-recovery risk tend to score below average.

Vertically integrated electric utilities are generally considered to have higher business risk than T&D utilities due to the risks associated with generation including fuel price and volume, operational and environmental risks. Among utilities with generation, those with significant exposure to fossil fuels, particularly coal, are typically viewed as having higher risk due to uncertainty as to the timing and amount of capital expenditures required to comply with further anticipated restrictions on environmental emissions including carbon dioxide, mercury, sulfur dioxide and nitrogen oxides.

Regulatory Framework Score is Utility Specific

It is important to note that our evaluation of a utility's regulatory framework is company specific, considering each company's experience and track record at cultivating supportive regulatory relationships and operating within its framework. Although utilities operating within the same framework will tend to have similar Factor 1 scores, it is possible to have deviations based on actual experience. For example:

In Florida, a historically supportive environment, Progress Energy Florida, Inc. and Florida Power & Light's recent sizeable rate increase requests, which were proposed against a backdrop of a significantly weakened economy, resulted in an unprecedented (for Florida) amount of political intervention, and rate increases that were severely limited, or denied. As a result, we have lowered the Factor 1 score for these companies to Baa from A. This does not necessarily mean that we would automatically lower the regulatory framework scores for all utilities in Florida to the same degree. Gulf Power Company, for example, which has not filed for a base rate increase in several years and is not expected to do so over the near term, is insulated to some extent from the current, perhaps temporarily deteriorated, political and regulatory environment in the state.

In Virginia, a regulatory environment also historically viewed as supportive, legislation passed in 2007 essentially to re-regulate the electric industry has impacted utilities differently. Virginia Electric and Power Company (VEPCO), in March received commission approval of a unanimous settlement agreement, which included a base rate ROE of 11.9%. The settlement resulted in no change in VEPCO's base rates (but did require significant refunds and rate credits); however, it also allows VEPCO to adjust rates via rider mechanisms for various transmission, generation and efficiency investments. As a result, cash flows are expected to remain adequate and VEPCO's Factor 1 score is currently A. On the other hand, in 2008 the commission rejected Appalachian Power Company's (APCO) proposed construction of an integrated gas combined cycle plant, and associated request for a premium ROE. In APCO's pending rate case, staff is recommending an increase of approximately $40 million, while a new state law resulted in the suspension of a $154 million interim increase put in place in December. APCO also has operations in West Virginia and its score on Factor 1 is currently Baa. Allegheny Energy Inc.'s Potomac Edison Company (PEC) had substantial difficulty recovering its increased costs for fuel and purchase power post a June 2007 expiration of a fixed rate contract with its affiliate. Recovery was not authorized until 2008, and was implemented, subject to caps, in July 2009. On June 1st, PEC completed of the sale of its Virginia operations to two electric cooperatives.

A utility's treatment within its regulatory framework, and our assessment of its Factor 1 score, often may have less to do with the regulator and much to do with the company and their cultivation of the regulatory relationship. It is entirely possible for a company to improve upon its regulatory relationships via open communication and negotiation toward the shared goals of providing reliable service at a reasonable cost. For example, regulatory relationships within PacifiCorp's numerous jurisdictions have generally all improved since its 2006 acquisition by MidAmerican Energy Holdings, Inc. as the company focused on understanding the needs and concerns of the regulators and other constituents within each state that it operates.

Other Considerations

On a company-specific basis, we would also evaluate factors such as the regulator's ability to oversee and ultimately approve utility mergers and acquisitions or their ability to encourage or require investments in renewable resources or energy efficiency. Environmental regulations, such as carbon capture or renewable portfolio standards could affect the regulatory framework score, particularly if they are especially onerous, for example in the U.S. southeast where renewable resources are limited. Nevertheless, these mandates are complex, usually have voluntary alternatives or offset provisions and can simply be re-legislated in the future which typically does not make these requirements a material credit issue at this time.

We also look at the substance of any regulatory or legal ring fencing provisions, including restrictions on dividends, capital expenditures and investments; separate financing provisions and/or legal structures; and limits on the ability of the regulated entity's ability to support its parent in times of financial distress. At any given time, depending on the circumstances facing the company, these may become contributing factors in determining the Factor 1 score.

Conclusion

A utility's regulatory framework is a key consideration in determining its credit quality - accounting for a significant 25% weighting - when we evaluate a utility's credit rating within the framework of our Rating Methodology.

When evaluating a utility's regulatory framework we consider such things as the independence of the regulatory body; the legislative or political environment; how developed the regulatory framework is; the regulator's track record for predictability and stability in terms of decision making; the business model of the utility; and the regulator's openness to consider alternative rate mechanisms.

Most of the utilities we rate operate in environments where regulators strive for a fair balance between assuring reliable customer service at a reasonable cost, while allowing a utility to earn a reasonable return. These companies generally score around the mid-Baa range.

Meanwhile, unusual regulatory conditions can affect a utility's credit rating for better or worse. Utilities operating in regulatory environments with a history of independent decision making and generally supportive regulatory actions receive the highest regulatory framework scores; generally within the A to Aa ranges – while those operating in environments prone to political pressure receive the lowest scores, generally within the B to Ba ranges.

Appendix A: Current Factor 1 scoring for the operating utilities in Moody's rated universe

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
Chubu Electric Power Company, Incorp.	CLP Power Hong Kong Limited	Alabama Power Company	Appalachian Power Company	Arizona Public Service Company	National Power Corporation
Chugoku Electric Power Company, Incorp.		ALLETE, Inc.	Avista Corp.	Cemig Geraçao e Transmissao	Power Sector Asset & Liabilities Management
Hokkaido Electric Power Company, Incorp.		Duke Energy Carolinas, LLC	Black Hills Power, Inc.	Companhia Energetica de Minas Gerais	Perusahaan Listrik Negara (P.T.)
Hokuriku Electric Power Company		FortisBC Inc	Central Vermont Public Service Corp.	Companhia Paranaense de Energia	
Kansai Electric Power Company, Incorp.		Georgia Power Company	Cleco Power LLC	EDP – Energias do Brasil	
Kyushu Electric Power Company, Incorp.		Hydro-Quebec	Columbus Southern Power Company	Empire District Electric Company (The)	
Okinawa Electric Power Company, Incorp.		Interstate Power & Light Company	Consumers Energy Company	Empresas Publicas de Medelin E.S.P.	
Tokyo Electric Power Company, Incorp.		Madison Gas and Electric Company	Dayton Power & Light Company	Eskom Holdings Ltd	
Tennessee Valley Authority		MidAmerican Energy Company	Detroit Edison Company (The)	Furnas Centrais Eletricas S.A	
		Mississippi Power Company	Duke Energy Indiana, Inc.	Israel Electric Corporation Limited (The)	
		Northern States Power Company (Minnesota)	Duke Energy Kentucky, Inc.	Kansas City Power & Light Company	
		Northern States Power Company (Wisconsin)	Duke Energy Ohio, Inc.	Light S.A.	
		Otter Tail Power Company	Eesti Energia AS	Monongahela Power Company	
		Progress Energy Carolinas, Inc.	EDA - Electricidade dos Acores, S.A.	NTPC Limited	
		South Carolina Electric & Gas Company	El Paso Electric Company	Public Service Company of New Mexico	
		Southern California Edison Company	Empresa de Electricidade da Madeira, S.A.	Tata Power Company Limited (The)	
		Pacific Gas & Electric Company	Entergy Arkansas, Inc.	Tucson Electric Power Company	
		San Diego Gas & Electric Company	Entergy Gulf States Louisiana, LLC	Union Electric Company	
		Virginia Electric and Power Company	Entergy Louisiana, LLC	UNS Electric	
		Wisconsin Electric Power Company	Entergy Mississippi, Inc.		
		Wisconsin Power and Light Company	Entergy New Orleans, Inc.		
		Wisconsin Public Service Corporation	Entergy Texas, Inc.		
			Florida Power & Light Company		
			Green Mountain Power Corporation		
			Gulf Power Company		
			Hawaiian Electric Company, Inc.		
			Idaho Power Company		
			Indiana Michigan Power Company		
			Indianapolis Power & Light Company		

Vertically Integrated Utilities

Aaa	Aa	A	Baa	Ba	B
			Kentucky Power Company		
			Kentucky Utilities Co.		
			Korea Electric Power Corporation		
			Korea East-West Power Co. Ltd		
			Korea Hydro and Nuclear Power Co. Ltd		
			Korea Midland Power Co. Ltd		
			Korea South-East Power Co. Ltd		
			Korea Southern Power Co. Ltd		
			Korea Western Power Co. Ltd		
			Latvenergo AS		
			Louisville Gas & Electric Company		
			Nevada Power Company		
			Northern Indiana Public Service Company		
			NorthWestern Corporation		
			Ohio Power Company		
			Oklahoma Gas & Electric Company		
			PacifiCorp		
			Portland General Electric Company		
			Progress Energy Florida, Inc.		
			Public Service Company of Colorado		
			Public Service Company of New Hampshire		
			Public Service Company of Oklahoma		
			Puget Sound Energy, Inc.		
			San Diego Gas & Electric Company		
			Sierra Pacific Power Company		
			Southern Indiana Gas & Electric Company		
			Southwestern Electric Power Company		
			Southwestern Public Service Company		
			Tampa Electric Company		
			Tenaga Nasional Berhad		

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	Empresa Distribuidora Norte S.A.
Oman Power and Water Procur. Co.	AEP Texas North Company	Central Hudson Gas & Electric Corporation	AES El Salvado Trust	Empresa Jujena de Energia S.A.
	CenterPoint Energy Houston Electric, LLC	Central Maine Power Company	Baltimore Gas and Electric Company	
	FortisAlberta Inc.	Cleveland Electric Illuminating Company (The)	Bandeirante Energia S.A.	
	Hydro One Inc.	Connecticut Light and Power Company	Cemig Distribuição S.A.	
	Newfoundland Power Inc.	Consolidated Edison Company of New York	Centrais Eletricas do Para S.A.	
	Oncor Electric Delivery Company	Jersey Central Power & Light Company	Centrais Eletricas Matogrossenses S.A.	
	Superior Water, Light and Power Company	Massachusetts Electric Company	Central Illinois Light Company	
	Texas-New Mexico Power Company	Metropolitan Edison Company	Central Illinois Public Service Company	
		Narragansett Electric Company	Commonwealth Edison Company	
		New England Power Company	Comp. de Ener. Eletr. do Est. do Tocantins	
		New York State Electric and Gas Corporation	Delmarva Power & Light Company	
		Niagara Mohawk Power Corporation	Duquesne Light Company	
		NSTAR Electric Company	Empresa Electrica de Guatemala, S.A.	
		Ohio Edison Company	Energisa Paraíba-Dist. de Energia S.A.	
		Orange and Rockland Utilities, Inc.	Energisa Sergipe - Dist. de Energia S.A.	
		PECO Energy Company	Escelsa	
		Pennsylvania Electric Company	GAIL (India) Ltd	
		Pennsylvania Power Company	Illinois Power Company	
		PPL Electric Utilities Corporation	Light Serviços	
		Public Service Electric and Gas Company	Perusahaan Gas Negara	
		Rochester Gas & Electric Corporation	Potomac Edison Company (The)	
		Toledo Edison Company	Potomac Electric Power Company	
		United Illuminating Company	Rede Energia	
		West Penn Power Company	Rio Grande Energia S.A. - RGE	
		Western Massachusetts Electric Company	Towngas China Co. Ltd	
			Xinao Gas Holdings Ltd	

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

Moody's Related Research

Rating Methodologies:

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

» Unregulated Utilities and Power Companies, August 2009 (118508)

Industry Outlooks:

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

Special Comments:

» Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality, June 2010 (122304)

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.

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Assessing U.S. Investor-Owned Utility Regulatory Environments

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Assessing U.S. Investor-Owned Utility Regulatory Environments

Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile. One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions where a utility operates. A utility management team's skill in dealing with regulatory risk can sometimes overcome a difficult regulatory environment. Conversely, companies' regulatory risk can increase even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. We modify our assessment of regulatory advantage to account for this dynamic in our ratings methodology (for the criteria we use to rate utilities, see "Corporate Methodology," and "Key Credit Factors For The Regulated Utilities Industry," published Nov. 19, 2013, on RatingsDirect.)

There are specific factors we use in the U.S. to assess the credit implications of the numerous regulatory jurisdictions here that help us determine the "preliminary regulatory advantage" in our credit analysis of each investor-owned regulated utility. We organize the subfactors of regulatory advantage into four categories:

- Regulatory stability,
- Tariff-setting procedures and design,
- Financial stability, and
- Regulatory independence and insulation.

Regulatory Stability

The foundation of our opinion of a jurisdiction is the stability of its approach to regulating utilities, encompassing transparency, predictability, and consistency. Given the maturity of the U.S. investor-owned utility industry, the long history of utility regulation (going back to the early 20th century) and the well-established constitutional protections accorded to utility investments, we emphasize the principle of consistency when weighing regulatory stability. We also incorporate the degree to which the regulatory framework either explicitly or implicitly considers credit quality in its design.

Regulatory Change Can Bring Stability, Or Take It Away

While stability is one of the four pillars of our approach to evaluating regulatory risk, experience shows us that it's not an absolute positive or negative for creditors. Change can boost or lessen risk, and any improvement in a regulatory regime will overcome any negative connotations of instability. A good example is Michigan, which in about 2008 revamped its whole approach to utility regulation. As implemented in subsequent years by the Michigan Public Service Commission, the reforms have almost completely transformed the regulatory environment in that state.

However, during any period of change, we see the uncertainties surrounding the process and the outcome as possible major causes of risk. A more recent and still ongoing example is New York, where the Public Service Commission's (NYPSC) Reforming the Energy Vision (REV) proceeding is possibly revving up risk for utilities. While the NYPSC seemed at first to be focusing more on high-minded policy questions than on making a lot of changes to day-to-day operations, the current phase could eventually disrupt the way utilities make money and affect their ability to earn the authorized return. If the end result is greater operating risk with no opportunity to earn greater returns, our assessment of the regulatory environment could change.

Durability of regulatory system

An established, dependable approach to regulating utilities is a hallmark of a credit-supportive jurisdiction. Creditors lend capital to utilities over long periods to fund the development of long-lived assets. A firm understanding of the basic "rules" that will govern how the utility will recover its costs, including servicing its debt and the return on its capital over an extended period, is essential to accurately assess credit risk. Major or frequent changes to the regulatory model invariably raise risk due to the possibility of future changes. Steady application of transparent, comprehensible policies and practices lowers risk.

How long a regulatory framework has been in place is the most important factor in this area. We view jurisdictions as most supportive when there have been no major changes or where the approach has been consistent for a long time and is not prone to further changes. Jurisdictions that have undergone a major, fundamental change in the regulatory paradigm that seems to be working well are a little less supportive, and less so a jurisdiction that is transitioning to a new regulatory approach. Credit risk rises if the transition attracts political attention. The less-supportive jurisdictions are those that frequently alter the basic regulatory approach. We also view the framework's development less favorably if policy disputes or legal actions cause contention, indicating that the political consensus regarding utility regulation is fragile.

Some jurisdictions permit competitive markets to prevail for some important functions of the delivery of utility services, notably wholesale markets for electricity and retail markets for electric or gas service. In others, vertical integration is the norm. A jurisdiction's credit-supportiveness is more prone to suffer if market forces directly influence major cost items that utilities could otherwise control through cost-based regulation because of the potential volatility it creates. The risk inherent in a market-based model is straightforward: utility rates are more volatile when markets influence them rather than fully embedded costs, and regulators are apt to resist full and timely recovery when market price changes are abrupt and substantial (and perhaps misunderstood). We observe less support for credit quality in jurisdictions that are in the midst of deregulating important parts of the utility framework. The uncertainty of the timing of reaching the outcome--and what the result will be--is a negative factor from a credit perspective. Utilities are also prone to financial stress when the transition to competition causes potential "rate shock" for customers that regulators could resist.

Transparency of regulatory framework and attitude toward credit quality

We believe regulation works best when it is rule-based. Creditor interests are better protected by the presence of and adherence to a pre-set code of rules and procedures that we can look to when assessing risk. Risk is lower when the rules are more transparent and when they take into account a utility's financial integrity. We regard jurisdictions that require regulators to protect utilities' financial soundness and have transparent policies and procedures as the most credit-supportive. We ascribe higher risk in jurisdictions where policies and procedures support financial integrity, but where inconsistency can selectively arise. We believe a jurisdiction provides even less support when transparency merely exists. We see less support when any of these credit factors are absent, or if the regulator's record on following precedent is poor.

Tariff-Setting Procedures

We review rate decisions as part of our surveillance on each U.S. utility. We focus on the jurisdiction's overall approach to setting rates and the process it uses to establish base rates (practices pertaining to separate tariff provisions for large expenses are in the "Financial Stability" part of our analysis). We focus on whether base rates, over time, fairly reflect a utility's cost structure and allow a fair opportunity to earn a compensatory return that provides creditors with a financial cushion that supports credit quality. If the process is geared toward an incentive-based system, our analysis centers on the risks related to the incentive mechanisms. If the jurisdiction has vertically integrated utilities, we review the resource procurement process and assess how it affects regulatory risk.

Rate Cases Can Affect Creditworthiness

Although not common, rate case outcomes can sometimes lead directly to a change in our opinion of creditworthiness. Often it's a case that takes on greater importance because of the issues being litigated. For example, in 2010, we downgraded Florida Power & Light and its affiliates following a Florida Public Service Commission rate ruling that attracted attention due to drastic changes to settled practices on rate case particulars like depreciation rates. More recently, in June 2016, we downgraded Central Hudson Electric & Gas due to our revised opinion of regulatory risk. While that reflected the company's own management of regulatory risk, it was prompted in part by other rate case decisions in New York that highlighted the overall risk in the state.

Sometimes change comes from outside the usual rate case process. The aforementioned improvement in Michigan (see the previous sidebar) came from legislative changes that reformed rate case procedures such as interim rate increases and time limits on rate decisions. In March 2016, we affirmed our ratings on Entergy Corp. and kept the outlook positive based on the prospect of lower regulatory risk as the company pursues strategic changes in its various jurisdictions. For instance, legislation in Arkansas allowing for formula rates could better enable Entergy to manage regulatory lag and earn its authorized return.

Ability to timely recover costs

We review authorized returns and capital structures in our analysis, but we focus mainly on actual earned returns. Examples abound of utilities with healthy authorized returns that have no meaningful expectation of earning those returns due to, for example, rate case lag (i.e., the relationship between approved rates and the age of the costs used to set those rates) or expense disallowances. Also, the stability of the returns is as important as the absolute level of financial returns, and we note the equity component in the capital structure used to generate the revenue requirement in rate proceedings. Higher authorized and earned returns and thicker equity ratios translate into better credit measures and a more comfortable equity cushion for creditors. We consider a regulatory approach that allows utilities the opportunity to consistently earn a reasonable return as a positive credit factor.

A very credit-supportive jurisdiction is one in which all of the utilities it regulates consistently earn above-average returns. We assess jurisdictions lower if only some of them do, and lower still if the earnings records are below average or highly variable from year to year. We deem jurisdictions as weaker when all utilities earn well-below-average returns, and we consider jurisdictions where all utilities consistently earn exceedingly poor returns, including years with negative returns, as weakest.

We consider "regulatory lag" along with the record of earned returns to assess timeliness. Credit-supportive jurisdiction typically have a track record of little regulatory lag, indicating that responsibility for a poor or uneven earnings history lies more with management than its regulators. In addition to the regulator's efficiency in completing rate cases, we consider the obsolescence of the costs on which the rates are based, the timing of interim rates, and other practices (such as allowing rates to automatically change in a future period based on inflation) that affect a utility's ability to earn its authorized return.

If a jurisdiction uses incentives as the primary ratemaking tool and institutes a comprehensive incentive program that allows revenues and costs to diverge, we evaluate the incentive mechanisms' effect on a utility's earnings capability and stability. A common approach features an extended period between base rate reviews, during which rates change according to a formula based on inflation, a predetermined productivity factor, and capital spending. An incentive-based program can be close to credit-neutral compared with systems that permit more frequent and dynamic rate changes if the risk is symmetrical (i.e., an equal opportunity to earn over or under the authorized return and equivalent reward or penalty for doing so) and limited (a maximum or minimum earnings band). The effect on regulatory risk depends on whether we believe the efficiency targets are realistic and achievable, the regulator's treatment of disparities in actual versus authorized spending, and the framework's flexibility to adjust returns for capital market conditions. If there are operating standards, we determine whether they fairly reward or punish utilities if performance deviates from expectations.

There is a muted effect on regulatory risk in jurisdictions where incentives are not central, but are instead used only to augment cost-of-service regulation. A moderate amount of incentives that carry symmetrical risks can even modestly support better credit quality. For example, a fuel-adjustment and purchased-power clause with a sharing mechanism that affects less than 10% of the total fuel costs and cuts both ways when commodity markets change can modestly reduce risk by offering the utility a mild incentive for effective procurement and efficient operations, without unduly exposing it to commodity price risk.

We typically view jurisdictions as credit-supportive if regulators use symmetrical incentive mechanisms sparingly in the rate-setting process. When incentives play a larger role in the rate-setting approach, but are well-designed to evenly allocate risk, we see less support for credit quality. We regard still lower jurisdictions where incentives dominate and are poorly designed. Jurisdictions where incentives significantly degrade risk and are part of a comprehensive incentive regime harbor the most risk for creditors.

Financial Stability

When we evaluate U.S utility regulatory environments, we consider financial stability to be of substantial importance. Cash takes precedence in credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision-making is one that will appeal to creditors.

Creative Ratemaking Can Help...If Used Correctly

The ability of financial stability factors to help a utility maintain and smooth its cash flow gives prominence to this area of our analysis. In addition to the near-ubiquitous fuel clauses, we see utilities give more attention to obtaining so-called "disc" mechanisms (DSIC, for distribution system investment charge, is a common acronym for this kind of rate adjustment) that accelerate and stabilize cash flow realization when a utility pursues a strategy of boosting rate base to fuel earnings growth.

For instance, Duquesne Light recently filed for a DSIC mechanism in Pennsylvania in conjunction with a long-term plan to improve its distribution system. Approval, requested for October, would enhance our view of Duquesne's ability to manage regulatory risk, because it would consequently be joining the other Pennsylvania utilities that already benefit from this mechanism. On the other end of the spectrum, Mississippi Power's ongoing travails in obtaining rate relief for its Kemper coal-fired plant, which has experienced significant cost and schedule problems, points to how regulatory risk can deteriorate under stress when well-established procedures for handling large and risky capital projects are absent or not followed.

Treatment of significant expenses

When utilities have major expenses such as fuel and purchased power/gas/water, the presence of separate tariff provisions to facilitate full and contemporaneous recovery is the most prominent factor in this part of our analysis. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of management's control is a key feature of a credit-supportive regulatory jurisdiction. The analysis centers on the special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect our analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part when we assess regulatory advantage.

We consider jurisdictions to be very credit-supportive if utilities can recover all high-expense items through an automatic tariff clause that is based on projected costs, adjusts frequently, and has no record of any significant disallowances. We see more risk if separate mechanisms exist, but lack some of the above features. We view jurisdictions that lack independent rate mechanisms for large expenses and have a record of significant disallowances as weakest.

Treatment of capital spending

When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.

Very supportive jurisdictions offer a separate recovery mechanism for all capital spending, a mandated current cash return during construction, and a bonus return for some or all capital projects. We deem a jurisdiction weaker if there is a separate mechanism for only certain kinds of spending and the cash return and higher return are subject to the regulator's discretion. We view jurisdictions that don't allow separate recovery or a current return as being lower on the scale. We assess a jurisdiction as weaker still when it doesn't have independent rate mechanisms for capital projects, and we view it as most risky when full recovery occurs only after a utility's assets become operational.

Cash-smoothing mechanisms

We have a more positive view of jurisdictions that use innovative regulatory provisions that help to smooth cash flow from period to period. For a jurisdiction that focuses on incentives in its basic approach to ratemaking, through multiyear rate plans or a formula rate plan, we view the availability of "reopeners" (to adjust rates for unexpected events out of the utility's control) as key to this part of our analysis. The utility's ability to petition for a rate increase when unexpected or uncontrollable costs arise in the midst of a long-term rate plan is a critical risk mitigant.

Other examples of risk-dampening regulatory policies include hedging program approvals, and decoupling (the separation of a utility's profits from sales) or weather-related mechanisms. If a utility seeks approval of a hedging program to manage exposure to commodity prices, it can reduce risk if there's a clearly stated hedging policy that its regulator has endorsed, and a track record of activity that conforms to the policy that has not been subject to regulatory second-guessing. A well-designed decoupling or weather-normalization mechanism that efficiently adjusts rates to offset the sales effect of economic conditions, customer usage trends, or weather will soften earnings and cash flow volatility to the benefit of creditors. If applicable, we view a record of regulatory responsiveness to extreme events for utilities that are prone to violent or disruptive weather (like hurricanes) as favorable for credit quality.

A jurisdiction is more credit-supportive if it makes extensive use of extraordinary and credit-supportive rate mechanisms. Also favorable are jurisdictions that use innovative mechanisms selectively, or have regulators that are receptive to reopeners where incentives are the main ratemaking method.

Regulatory Independence And Insulation

The role of politics in U.S. utility regulation is often misunderstood. In most jurisdictions, the regulator's function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service, but for other constituents as well. Creditors should recognize that utility regulation harbors political as well as economic risks. Therefore, how politics could influence regulation helps us evaluate a regulatory environment.

Political Influence On Utility Regulation Can Yield Unexpected Results

This is often the most variable area of our analysis and the most difficult to assess. The most dramatic, fairly recent reminder of how political forces can influence regulatory risk was last year's unexpected reversal by the popularly elected Mississippi Supreme Court of a significant rate increase granted for Mississippi Power to help pay for a major power plant under construction. Regulators, who were ordered to roll back rates and issue refunds, struggled to make decisions amid the strained political atmosphere and extra scrutiny that the Court's action had created. The episode also highlighted the greater regulatory risk that attends jurisdictions that expose regulators (and in this case the appellate court) to direct political accountability.

Another more recent example of political influence on regulation underscores the complexity of this area of analysis, because it featured many participants at both the federal and state level. Electric utilities in Ohio had a credible strategy for dealing with rising competitive risks in their merchant generation portfolios by offering the output to retail customers at pre-set prices on a long-term basis, which the state regulator approved. The federal regulator (Federal Energy Regulatory Commission, or FERC), responding to complaints by other generators that the plan would inhibit the operation of the competitive electricity market, essentially overruled the Ohio regulators and blocked the utilities from pursing the strategy that would have reduced its risk profile. It essentially decided that its political interest in and ideological commitment to efficient electricity markets overrode the state's political interest in stable electric rates. The saga is still continuing with attempts to bypass the FERC's ruling through other means, but no matter what the ultimate result, we see how political considerations can increase risk.

Political independence of regulator

The primary factor in this part of our analysis is the regulators' (and, when relevant, the judicial body that reviews the regulators' decisions) political independence. We think it's more credit-supportive when the regulator is substantially independent of the political process. Jurisdictions are somewhat less favorable when insulation is strong, such as when the executive branch of government appoints regulators subject to legislative approval. We consider jurisdictions to be further down the scale when the same voters who pay utility bills directly elect the regulators, but institutional efforts have been made to erect some shield for regulators from transient political concerns. We view jurisdictions that arrange for direct political accountability of regulators that persistently influences regulatory decisions as less supportive.

Record of direct political intervention

The overall atmosphere that a regulator operates in can affect its ability to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utilities in managing business and financial risk. In this part of our