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"For a regulated utility, the predictability and supportiveness of the regulatory *framework* in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors."

"For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability."

Moody's – Regulated Electric and Gas Utilities, August 2009; page 6

Moody's Global Infrastructure Finance

Rating Methodology

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(Continued on back page)

August 2009

Regulated Electric and Gas Utilities

Summary

This rating methodology provides guidance on Moody's approach to assigning credit ratings to electric and gas utility companies worldwide whose credit profile is influenced to a large degree by the presence of regulation. It replaces the Global Regulated Electric Utilities methodology published in March 2005 and the North American Regulated Gas Distribution Industry (Local Distribution Companies) methodology published in October 2006. While reflecting similar core principles as these previous methodologies, this updated framework incorporates refinements that better reflect the changing dynamics of the regulated electric and gas industry and the way Moody's applies its industry methodologies.

The goal of this rating methodology is to assist investors, issuers, and other interested parties in understanding how Moody's arrives at company-specific ratings, what factors we consider most important for this sector, and how these factors map to specific rating outcomes. Our objective is for users of this methodology to be able to estimate a company's ratings (senior unsecured ratings for investment-grade issuers and Corporate Family Ratings for speculative-grade issuers) within two alpha-numeric rating notches.

Regulated electric and gas companies are a diverse universe in terms of business model (ranging from vertically integrated to unbundled generation, transmission and/or distribution entities) and regulatory environment (ranging from stable and predictable regulatory regimes to those that are less developed or undergoing significant change). In seeking to differentiate credit risk among the companies in this sector, Moody's analysis focuses on four key rating factors that are central to the assignment of ratings for companies in the sector. The four key rating factors encompass nine specific elements (or sub-factors), each of which map to specific letter ratings (see Appendix A). The four factors are as follows:

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

Moody's Investors Service

This methodology pertains to regulated electric and gas utilities and excludes regulated electric and gas networks (companies primarily engaged in the transmission and/or distribution of electricity and/or natural gas that do not serve retail customers) and unregulated utilities and power companies, which are covered by separate rating methodologies. Municipal utilities and electric cooperatives are also excluded and covered by separate rating methodologies.

In Appendix A of this methodology, we have included a detailed rating grid for the companies covered by the methodology. For each company, the grid maps each of these key rating factors and shows an indicated alpha-numeric rating based on the results from the overall combination of the factors (see Appendix B). We note, however, that many companies will not match each dimension of the analytical framework laid out in the rating grid exactly and that from time to time a company's performance on a particular rating factor may fall outside the expected range for a company at its rating level. These companies are categorized as "outliers" for that rating factor. We discuss some of the reasons for these outliers in this methodology as well as in published credit opinions and other company-specific analysis.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector. The grid provides summarized guidance on the factors that are generally most important in assigning ratings to the sector. While the factors and sub-factors within the grid are designed to capture the fundamental rating drivers for the sector, this grid does not include every rating consideration and does not fit every business model equally. Therefore, we outline additional considerations that may be appropriate to apply in addition to the four rating factors. Moody's also assesses other rating factors that are common across all industries, such as event risk, off-balance sheet risk, legal structure, corporate governance, and management experience and credibility. Furthermore, most of our sub-factor mapping uses historical financial results to illustrate the grid while our ratings also consider forward looking expectations. As such, the grid-indicated rating is not expected to always match the actual rating of each company. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this methodology does not attempt to provide an exhaustive list of every factor that can be relevant to a utility's ratings. For example, our analysis covers factors that are common across all industries (such as coverage metrics, debt leverage, and liquidity) as well as factors that can be meaningful on a company or industry specific basis (such as regulation, capital expenditure needs, or carbon exposure).

This publication includes the following sections:

- **About the Rated Universe**: An overview of the regulated electric and gas industries
- **About the Rating Methodology**: A description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

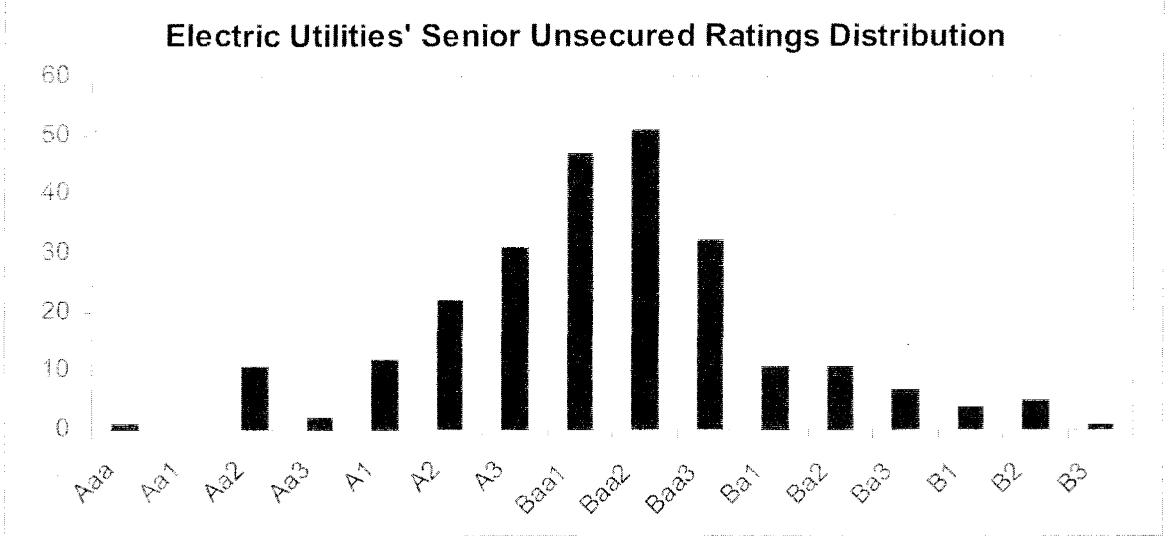
In the appendices, we also provide tables that illustrate the application of the methodology grid to 30 representative electric and gas utility companies with explanatory comments on some of the more significant differences between the grid-implied rating and our actual rating (Appendix C). We also provide definitions of key ratios (Appendix D), an industry overview (Appendix E) and a discussion of the key issues facing the industry over the intermediate term (Appendix F) and regional considerations (Appendix G).

About the Rated Universe

The rating methodology covers investor-owned and commercially oriented government owned companies worldwide that are engaged in the production, transmission, distribution and/or sale of electricity and/or natural gas. It covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution companies, some U.S. transmission-only companies, and local gas distribution companies (LDCs). For the LDCs, we note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas companies that have significant non-utility businesses[1]. In addition, this methodology *includes both holding* companies as well as operating companies. For holding companies, actual ratings may be lower than methodology grid-implied ratings due to the structural subordination of the holding company debt to the operating company debt. In order for a utility to be covered by this methodology, the company must be an investor-owned or commercially oriented government owned entity and be subject to some degree of government regulation or oversight. This methodology excludes regulated electric and gas networks, electric generating companies[2] and independent power producers operating predominantly in unregulated power markets, municipally owned utilities, electric cooperative utilities, and power projects, which are covered in separate rating methodologies.

The rated universe includes approximately 250 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. They account for about US$650 billion of total outstanding long-term debt instruments. In general, ratings used in this methodology are the Senior Unsecured ("SU") rating for investment grade companies, the Corporate Family Rating ("CFR") for non-investment grade companies, and the Baseline Credit Assessment ("BCA") for Government Related Issuers (GRI). A subset of 30 of these entities is included in the methodology, representing a sampling of the universe to which this methodology applies.

Geographically, this methodology covers companies in the Americas, Europe, Middle East, Africa, Japan, and the Asia/Pacific region. The ratings spectrum for the sector ranges from Aaa to B3, with the actual rating distribution of the issuers included (both holding companies and operating companies) shown on the following table:



Although all of these companies are affected to some degree by government regulation or oversight, country-by-country regulatory differences and cultural and economic characteristics are also important credit considerations. There is little consistency in the approach and application of regulatory frameworks around the world. Some regulatory frameworks are highly supportive of the utilities in their jurisdictions, in some cases offering implied sovereign support to ensure reliability of electric supply. Other regulatory frameworks are less supportive, more unpredictable or affected by political influence that can increase uncertainty and negatively affect overall credit quality.

1 These companies are assessed under the rating methodology "North American Diversified Natural Gas Transmission and Distribution Companies", March 2007.

2 The six Korean generation companies are included in this methodology as they are subject to regulation and Moody's views them and their 100% parent and sole off-taker KEPCO on a consolidated basis. The Brazilian generation companies are included as they are also subject to regulatory intervention.

About this Rating Methodology

Moody's approach to rating companies in the regulated electric and gas utility sector, as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

In general, Moody's rating committees for the regulated electric and gas utility sector focus on a number of key rating factors which we identify and quantify in this methodology. A change in one or more of these factors, depending on its weighting, is likely to influence a utility's overall business and financial risk. We have identified the following four key rating factors and nine sub-factors when assigning ratings to regulated electric and gas utility issuers:

Rating Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%		25%
Ability to Recover Costs and Earn Returns	25%		25%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Liquidity and Key Financial Metrics	40%	Liquidity	10%
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	7.5%
		CFO pre-WC - Dividends / Debt	7.5%
		Debt/Capitalization or Debt / Regulated Asset Value	7.5%
Total	**100%**		**100%**

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

These factors are critical to the analysis of regulated electric and gas utilities and, in most cases, can be benchmarked across the industry. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2. Measurement of the Key Rating Factors

We next explain the elements we consider and the metrics we use to measure relative performance on each of the four factors. Some of these measures are quantitative in nature and can be specifically defined. However, for other factors, qualitative judgment or observation is necessary to determine the appropriate rating category.

Moody's ratings are forward looking and attempt to rate through the industry's characteristic volatility, which can be caused by weather variations, fuel or commodity price changes, cost deferrals, or reasonable delays in regulatory recovery. The rating process also makes extensive use of historic financial statements. Historic results help us understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes. All financial measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts for (among other things) underfunded pension obligations and operating leases.

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match the performance of each factor and sub-factor to one of Moody's broad rating categories (Aaa, Aa, A, Baa, Ba, and B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of CFO pre-WC plus Interest/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

For each factor and sub-factor, we provide a table showing how a subset of the companies covered by the methodology maps within the specific factors and sub-factors. We recognize that any given company may perform higher or lower on a given factor than its actual rating level will otherwise indicate. These companies are identified as "outliers" for that factor. A company whose performance is two or more broad rating categories higher than its rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers for each factor.

5. Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall rating, each of the factors and sub-factors is converted into a numeric value based on the following scale:

Ratings Scale

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

Each sub-factor's numeric value is multiplied by an assigned weight and then summed to produce a composite weighted-average score. The total sum of the factors is then mapped to the ranges specified in the table below, and the indicated alpha-numeric rating is determined based on where the total score falls within the ranges.

Factor Numerics

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	< 1.5
Aa1	1.5 < 2.5
Aa2	2.5 < 3.5
Aa3	3.5 < 4.5
A1	4.5 < 5.5
A2	5.5 < 6.5
A3	6.5 < 7.5
Baa1	7.5 < 8.5
Baa2	8.5 < 9.5
Baa3	9.5 < 10.5
Ba1	10.5 < 11.5
Ba2	11.5 < 12.5
Ba3	12.5 < 13.5
B1	13.5 < 14.5
B2	14.5 < 15.5
B3	15.5 < 16.5

For example, an issuer with a composite weighting factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the four broad rating categories.

The Key Rating Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

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

Rating Factor 1: Regulatory Framework (25%)

Why it Matters

For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. The latter is largely addressed in Factor 2, Ability to Recover Cost and Earn Returns, discussed below. However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions.

How We Measure It for the Grid

For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor. Consideration is given to the substance of any regulatory ring fencing provisions, including restrictions on dividends; restrictions on capital expenditures and investments; separate financing provisions; separate legal structures; and limits on the ability of the regulated entity to support its parent company in times of financial distress. The criteria for each rating category are outlined in the factor description within the rating grid.

For regulated electric utilities with some unregulated operations, consideration will be given to the competitive and business position of these unregulated operations[3]. 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 electric utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be if the utility had solely regulated operations.

Moody's views the regulatory risk of U.S. utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia, and Canada The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the U.S. results in stronger competition in wholesale power markets; U.S. fuel and power markets are more

3 For diversified gas companies, the "North American Diversified Natural Gas Transmission and Distribution Company" rating methodology is applied.

volatile; there is a low likelihood of extraordinary political action to support a failing company in the U.S.; holding company structures limit regulatory oversight; and overlapping or unclear regulatory jurisdictions characterize the U.S. market. As a result, no U.S. utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor.

The scores for this factor replace the classifications we had been using to assess a utility's regulatory framework, namely, the Supportiveness of Regulatory Environment (SRE) framework, outlined in our previous rating methodology (Global Regulated Electric Utilities, March 2005), which we are phasing out. Generally speaking, an SRE 1 score from our previous methodology would roughly equate to Aaa or Aa ratings in this methodology; an SRE 2 score to A or high Baa; an SRE 3 score to low Baa or Ba, and an SRE 4 score to a B. For U.S. and Canadian LDCs, this factor corresponds to the "Regulatory Support" and "Ring-fencing" factors in our previous methodology (North American Regulated Gas Distribution, October 2006).

Factor 1 – Regulatory Framework (25%)

Aaa	Aa	A	Baa	Ba	B
Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.

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

Why It Matters

Unlike Factor 1, which considers *the general regulatory* framework under which a utility operates and the overall business position of a utility within that regulatory framework, this factor addresses in a more specific manner the ability of an individual utility to recover its costs and earn a return. The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. The reluctance to provide rate relief reflected regulatory commission concerns about the impact of large rate increases on customers as well as debate about the appropriateness of the relief being sought by the utility and views of imprudency. Currently, the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed.

How We Measure It for the Grid

For regulated utilities, the criteria we consider include the statutory protections that are in place to insure full and timely recovery of prudently incurred costs. In its strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to *rate increases* or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan, for example, where the utilities in that country receive a score of Aa for this factor.

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

For regulated electric utilities that have some unregulated operations, we assess the likelihood that the utility will be able to pass on costs of its unregulated businesses to unregulated customers. Among the criteria we use to judge this factor include the number and types of different businesses the company is in; its market share in these businesses; whether there are significant barriers to entry for new competitors; and the degree to which the utility is vertically integrated. Those utilities with *several businesses with large market shares* are generally in a better position to pass on their costs to unregulated customers. Those utilities that have lower market shares in their unregulated activities or are in businesses with few barriers to entry will likely be more at risk in passing on costs, and thus would receive lower scores. A high proportion of unregulated businesses or a higher risk of passing on costs to unregulated customers could result in a lower score for this factor than would apply if the business was completely regulated.

For U.S. and Canadian LDCs, this factor addresses the "Sustainable Profitability" and "Regulatory Support" assessments in the previous LDC rating methodology. While LDCs' authorized returns are comparable to those for their electric counterparts, the smaller, more mature LDCs tend to face less regulatory challenges. Purchased Gas Adjustment mechanisms are the norm and they have made strides in implementing alternative rate designs that decouple revenues from volumes sold.

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

Aaa	Aa	A	Baa	Ba	B
Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.

Rating Factor 3 - Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that any one part of the company will have a severe negative impact on cash flow and credit quality. In general, a balance among several different businesses, geographic regions, regulatory regimes, generating plants, or fuel sources will diminish concentration risk and reduce the risk that a company will experience a sudden or rapid deterioration in its overall creditworthiness because of an adverse development specific to any one part of its operations.

How We Measure It For the Grid

For transmission and distribution utilities, local gas distribution companies, and other companies without significant generation, *the key criterion* we use is the diversity of their operations among various markets, geographic regions or regulatory regimes. For these utilities, the first set of criteria, labeled market diversification, account for the full 10% weighting for this factor. A predominately T&D utility with a high degree of diversification in terms of market and/or regulatory regime is less likely to be affected by adverse or unexpected developments in any one of these markets or regimes, and thus will receive the highest scores for this factor. Smaller T&D utilities operating in a limited market area or under the jurisdiction of a single regulatory regime will score lower on the factor, with those that are concentrated in an emerging market or riskier environment receiving the lowest scores.

For vertically integrated utilities with generation, the diversification factor is broadened to include not only the criteria discussed above, but also takes into consideration the diversity of their generating assets and the type of fuel sources which they rely on. An additional but somewhat related consideration is the degree to which the utility is exposed to (or insulated from) commodity price changes. A utility with a highly diversified fleet of generating assets using different types of fuels is generally better able to withstand changes in the price of a particular fuel or additional costs required for particular assets, such as more stringent environmental compliance requirements, and thus would receive a higher rating for this sub-factor. Those utilities with more limited diversification or that are more reliant on a single type of generation and fuel source (measured by energy produced) will be scored lower on this sub-factor. Similarly, those utilities with a high reliance on coal and other carbon emitting generating resources will be scored lower on this factor due to their vulnerability to potential carbon regulations and accompanying carbon costs.

Generally, only the largest vertically integrated utilities or transmission companies with substantial operations that are multinational or national in scope, or whose operations encompass a substantial region within a single country, will receive scores in the highest Aaa or Aa categories for this factor. In the U.S., most of the largest multi-state or multi-regional utilities are scored in the A category, *most of* the larger single state utilities are scored Baa, and smaller utilities operating in a single state or within a single city are scored Ba. A utility may also be scored higher if it is a combination electric and gas utility, which enhances diversification.

The diversification factor was not included in the previous North American LDC methodology. Most LDCs are small and tend to have little geographic and regulatory diversity. However, they tend to be highly stable due to their customer base and margins that comprise primarily of a large number of residential and small commercial customers that are captive to the utility. This customer composition tends to result in a more stable operating performance than those that have concentrations in certain industrial customers that are prone to cyclicality or to bypassing the LDC to obtain gas directly from a pipeline. Pure LDCs are scored under the "Market Position" sub-factor for a full 100% under this factor. As with transmission and distribution utilities, no scores are given for "Fuel/Generation Diversification" as this sub-factor would not be applicable.

Factor 3: Diversification (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/ regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

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

Rating Factor 4 – Financial Strength and Liquidity (40%)

Why It Matters

Since most electric and gas utilities are highly capital intensive, financial strength and liquidity are key credit factors supporting their long-term viability. Financial strength and liquidity are also important to the maintenance of good relationships with regulators, to assure adequate regulatory responsiveness to rate increase requests and for cost recovery, and to avoid the need for sudden or unexpected rate increases to avoid financial problems. Financial strength is also important due to the ongoing need to invest in generation, transmission, and distribution assets that often require substantial amounts of debt financing. Utilities are among the largest debt issuers in the world and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility.

Although ratio analysis is a helpful way of comparing one company's performance to that of another, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. The relative strength of a company's financial ratios must take into consideration the level of business risk associated with the more qualitative factors in the methodology. *Companies with a lower business risk can have weaker credit metrics than those with higher business risk for the same rating category.*

Given the long-term nature of many of the capital intensive projects undertaken in the industry and the need to obtain regulatory recovery over an often multi-year time period, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from the historic 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.

How We Measure It For the Grid

In addition to assigning a score for a utility's overall liquidity position and relative access to funding sources and the capital markets, we have identified four key core ratios that we consider the most useful in the analysis of regulated electric and gas utilities. The four ratios are the following:

- Cash from Operations (CFO) pre-Working Capital Plus Interest / Interest
- Cash from Operations (CFO) pre-Working Capital / Debt
- Cash from Operations (CFO) pre-Working Capital – Dividends / Debt
- Debt/Capitalization or Debt / Regulated Asset Value (RAV)

The use of Debt / Capitalization or Debt / Regulated Asset Value will depend largely on the regulatory regime in which the utility operates, as explained below. These credit metrics incorporate all of the standard adjustments applied by Moody's when analyzing financial statements, including adjustments for certain types of off-balance sheet financings and certain other reclassifications in the income statement and cash flow statement.

These cash flow based ratios replace the earnings based metrics in the previous "North American Local Gas Distribution Company" rating methodology, reducing the impact on the grid results from non-cash items, such as pension expense.

The ratio calculations utilized and published for the companies covered by this methodology (including the 30 representative electric and gas utility companies highlighted) are historical three-year averages for the years 2006-2008. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios.

Measurement Criteria

Liquidity

Liquidity analysis is a key element in the financial analysis of electric and gas utilities and encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources. Sources of funds are compared to a company's cash needs and other obligations over the next twelve months. The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those utilities that are financially robust under all or virtually all scenarios, with little to no need for external funding and with unquestioned or superior access to the capital markets. Most utilities, however, receive more moderate scores of between "A" and "Baa" in this sub-factor as most need to rely to some degree on external funding sources to finance capital expenditures and meet other capital needs. Below investment grade scores on the sub-factor are assigned to utilities with weak liquidity or those that rely heavily on debt to finance investments.

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

The cash flow interest coverage ratio is a basic measure of a utility's ability to cover the cost of its borrowed capital and is an important analytical tool in this highly capital intensive industry. The numerator in the ratio calculation is a measure of cash flow excluding working capital movements plus interest expense, which can vary in significance depending on the utility. The use of CFO pre-WC is more comprehensive than Funds from Operations (FFO) under U.S. Generally Accepted Accounting Principles (GAAP) since it also captures the changes in long-term regulatory assets and liabilities. However, under International Financial Reporting Standards (IFRS), the two measures are essentially the same. The denominator in the ratio calculation is interest expense, which incorporates our standard adjustments to interest expense, such as including capitalized interest and re-classifying the interest component of operating lease rental expense. In Brazil, the cash interest amount is adjusted by the variation of non-cash financial expenses derived from foreign exchange and inflation denominated debt.

CFO pre-Working Capital / Debt

This metric measures the cash generating ability of a utility compared to the aggregate level of debt on the balance sheet. This ratio is useful in comparing utilities, many of which maintain a significant amount of leverage in their capital structure. The debt calculation takes into consideration Moody's standard adjustments to balance sheet debt, such as for operating leases, underfunded pension liabilities, basket-adjusted hybrids, guarantees, and other debt-like items.

CFO pre-Working Capital – Dividends / Debt

This ratio is a measure of 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 and can affect the ability of a utility to cover its debt obligations. 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. Moody's expects that even the financially strongest utilities will need to issue debt on a regular basis to maintain a target capital structure if their asset bases are growing. If a utility with an expanding asset base funds all of its capital expenditures with internally generated cash flow then, in the extreme, the utility's debt to capitalization will trend toward zero.

Debt/Capitalization or Debt/Regulated Asset Value or RAV

This ratio is a traditional measure of leverage and can be a useful way to gauge a utility's overall financial flexibility in light of its overall debt load. High debt to capitalization levels are not only an indicator of higher interest obligations, but can also 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. The denominator of the debt / capitalization ratio includes Moody's standard adjustments, the most important of which for some utilities is the inclusion of deferred taxes in capitalization, which tempers the impact of our debt adjustment.

While debt/capitalization is used predominantly in the Americas, other regions may use a variation of this ratio, namely, debt/regulated asset value or RAV ratio. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services and the RAV represents the value on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules (i.e. Australia and Japan), debt/RAV is viewed as superior to debt / capitalization as a credit measure and will be used for this sub-factor. Where RAV does not exist (i.e. North America and most Asian countries) or the method of calculation is subject to arbitrary or unpredictable revisions, we use debt/capitalization.

Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)							
	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Rating Methodology Assumptions and Limitations, and other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The four rating factors 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 to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be impacted by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, and other factors. In either case, we acknowledge that estimating future performance is subject to the risk of substantial inaccuracy.

In choosing metrics for this rating methodology grid, we did not 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, financial controls, and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them 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 only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, financial controls, and emerging market risk, where ratings might be constrained by the uncertainties associated with the local operating, political and economic environment, including possible government interference.

Actual assigned ratings may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, although Factors 1 and 2 address regulation and cost recovery, in some instances the effect of a company's financial strength and liquidity in Factor 4 will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 30 representative utilities highlighted, the methodology grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

- 30% or 9 companies map to their assigned rating
- 50% or 15 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating
- 20% or 6 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

Grid-Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch	Map to Within Two Notches
American Electric Power Company, Inc.	Cemig Distribuicao S.A.	Duke Energy Corporation
Arizona Public Service Company	Consolidated Edison Company of New York	Eesti Energia AS
CLP Holdings Limited	Dominion Resources, Inc.	Eskom Holdings Ltd
Consumers Energy Company	EDP - Energias do Brasil S.A.	Korea Electric Power Corporation
Florida Power & Light Company	Emera Incorporated	Northern Illinois Gas Company
PG&E Corporation	The Empire District Electric Company	Tokyo Electric Power Company
Piedmont Natural Gas Company, Inc.	FirstEnergy Corp.	
The Southern Company	Indianapolis Power & Light Company	
Xcel Energy Inc.	Kyushu Electric Power Company	
	Oklahoma Gas and Electric Co.	
	PECO Energy Company	
	Progress Energy Carolinas, Inc.	
	Southern California Edison Company	
	Westar Energy, Inc.	
	Wisconsin Power and Light Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1: Regulatory Framework

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.	25%

Factor 2: Ability to Recover Costs and Earn Returns

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.	25%

Factor 3: Diversification

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

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

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/ Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Appendix B: Methodology Grid-Indicated Ratings

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	Aa3	Aaa	Aa	Aa	A	Aaa	A	Aa	Aa	Ba	Ba	Baa
Tokyo Electric Power Company, Incorporated	Aa2	A1	Aaa	Aa	Aa	A	Aaa	Baa	Aa	A	Ba	Ba	Ba
Eesti Energia AS	A1/[8]	A3	Baa	Baa	B	B	B	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	A1	A	A	Baa	Baa	Baa	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	Baa1	Baa	Baa	Baa	Baa	A	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A2	A	A	A	A	A	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa1	Baa	Baa	A	A	N/A	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A3	Baa	A	Baa	Baa	Baa	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A3	A	A	Baa	Baa	Baa	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa1	Baa	A	Baa	Baa	N/A	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	Baa1	Baa	Baa	Baa	Baa	N/A	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	A3	A	A	A	A	N/A	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A2	A	A	Baa	Baa	A	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	Baa1	Baa	Baa	Baa	Baa	A	A	A	A	A	A	Baa
The Southern Company	A3	A3	A	A	Baa	A	Ba	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa1	Baa	Baa	A	Baa	Aa	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa2	Baa	Baa	Baa	A	Ba	Baa	Baa	Baa	Baa	Baa	Ba

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Arizona Public Service Company	Baa2	Baa2	Ba	Baa	Baa	Baa	Baa	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa2	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A3	Baa	A	Baa	A	Baa	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Baa1	A	A	Ba	Ba	Ba	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa3	Ba	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2[13]	Ba1	Ba	Ba	B	Ba	B	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa1	Baa	A	Ba	Baa	Ba	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	Baa2	Ba	Ba	Ba	Ba	N/A	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa2	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa2	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa3	Ba	Ba	Baa	Baa	Baa	Baa	Ba	Baa	Aa	A	A

Positive Outlier
Negative Outlier

Appendix C: Observations and Outliers for Grid Mapping

Results of Mapping Factor 1

Factor 1: Regulatory Framework

Factor Weight		25%
	Current Rating /BCA	Regulatory Supportiveness
Kyushu Electric Power Company, Incorporated	Aa2	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aaa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	Baa
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	Baa
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	Baa
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Ba
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	Baa
Duke Energy Corporation	Baa2	Baa
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Ba
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	Baa
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

As a utility's regulatory framework is one of the most important drivers of ratings, there are no outliers for this factor among the 30 issuers highlighted for this methodology.

Results of Mapping Factor 2

Factor 2: Ability to Recover Costs and Earn Returns

Factor Weight		25%
	Current Rating/BCA	Rate Adjustment and Cost Recovery Mechanisms
Kyushu Electric Power Company, Incorporated	Aa2	Aa
Tokyo Electric Power Company, Incorporated	Aa2	Aa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	A
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	A
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	A
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Baa
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	A
Duke Energy Corporation	Baa2	A
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Baa
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	A
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

Like Factor 1, Regulatory Framework, the ability to recover costs and earn returns is also an important ratings driver for regulated utilities, and it is not surprising that there are no outliers among the 30 issuers highlighted. For this factor, most of the issuers score exactly at their current rating levels, with the remainder scoring within one notch of their actual rating.

Results of Mapping Factor 3

Factor 3: Diversification

Sub-Factor Weights			5% *	5% **
	Current Rating/BCA	Indicated Factor 3 Rating	Market Position	Generation and Fuel Diversification
Kyushu Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Eesti Energia AS	A1/[8]	B	B	B
Florida Power & Light Company	A1	Baa	Baa	Baa
Korea Electric Power Corporation	A2/[6]	Baa	Baa	A
CLP Holdings Limited	A2	A	A	A
Northern Illinois Gas Company	A2	A	A	N/A
Oklahoma Gas and Electric Company	A2	Baa	Baa	Baa
Wisconsin Power and Light Company	A2	Baa	Baa	Baa
Consolidated Edison Company of New York	A3	Baa	Baa	N/A
PECO Energy Company	A3	Baa	Baa	N/A
Piedmont Natural Gas Company, Inc.	A3	A	A	N/A
Progress Energy Carolinas, Inc.	A3	Baa	Baa	A
Southern California Edison Company	A3	Baa	Baa	A
The Southern Company	A3	Baa	A	Ba
PG&E Corporation	Baa1	A	Baa	Aa
Xcel Energy Inc.	Baa1	A	A	A
American Electric Power Company, Inc.	Baa2	Baa	A	Ba
Arizona Public Service Company	Baa2	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa
Dominion Resources, Inc.	Baa2	A	A	A
Duke Energy Corporation	Baa2	Baa	A	Baa
Emera Incorporated	Baa2	Ba	Ba	Ba
The Empire District Electric Company	Baa2	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	B	Ba	B
Indianapolis Power & Light Company	Baa2	Ba	Baa	Ba
Cemig Distribuição S.A.	Baa3	Ba	Ba	N/A
FirstEnergy Corp.	Baa3	Baa	A	Baa
Westar Energy, Inc.	Baa3	Ba	Baa	Ba
EDP - Energias do Brasil S.A.	Ba1	Baa	Baa	Baa

Observations and Outliers

Of the 30 issuers highlighted, there are three outliers, including PG&E Corporation as a positive outlier, due to their high degree of generation diversification and the lack of coal in their generation mix, and both Eesti Energia AS and The Southern Company as negative outliers. As an Estonian vertically integrated dominant electric utility, Eesti Energia is exposed to considerably high concentration risk as it operates in one of the smallest CEE emerging markets. The concentration risk is further worsened by the company's high reliance on one fuel source as its generation is fully based on internationally rare oil shale. Furthermore, as the oil shale generation is relatively CO2 intensive, Eesti Energia is further exposed to the development of CO2 allowance prices. The Southern Company is one of the largest coal generating utility systems in the U.S., with a high percentage of its generation from carbon fuels.

Results of Mapping Factor 4

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Sub-Factor Weights	Current Rating/BCA	Indicated Factor 4 Rating	10% Liquidity	7.5% 3 Year Average CFO pre-WC + Interest/ Interest	7.5% 3 Year Average CFO pre-WC / Debt	7.5% 3 Year Average CFO pre-WC / Debt	7.5% 3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	A	Aa	Aa	Ba	Ba	Baa*
Tokyo Electric Power Company, Incorporated	Aa2	Baa	Aa	A	Ba	Ba	Ba*
Eesti Energia AS	A1/[8]	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	A	A	A	A	A	Baa
The Southern Company	A3	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Arizona Public Service Company	Baa2	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa	Ba	Baa	Aa	A	A

*Debt/RAV

Positive Outlier

Negative Outlier

Observations and Outliers

This factor takes into account historic financial statements. Historic results help us to understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

While the vast majority of utilities' key financial metrics map fairly closely to their ratings, there are several significant outliers, which generally fall into two broad groups. The first group is composed of negative outliers and include several utilities located in stable and supportive regulatory environments and are characterized by very low business risk. In these cases, the utilities may have lower financial ratios and higher leverage than most peer companies on a global basis, but still maintain higher overall ratings. In short, the certainty provided by regulatory stability and low business risk offsets any risks that may result from lower financial ratios. Examples of such negative outliers on the financial strength factor include most of the major Japanese utilities, including Tokyo Electric Power and Kyushu Electric Power.

The second group of outliers is composed of positive outliers, whereby several financial ratios are stronger than the overall Moody's rating. These include several utilities in Latin America, such as Cemig Distribuicao, EDP-Energias do Brasil, and European Eesti Energia, which exhibit strong financial coverage ratios and low debt levels, but where ratings are constrained by a more difficult regulatory or business environment or a sovereign rating ceiling.

Appendix D: Definition of Ratios

Cash Flow Interest Coverage

(Cash Flow from Operations – Changes in Working Capital + Interest Expense) / (Interest Expense + Capitalized Interest Expense)

CFO pre-WC / Debt

(Cash Flow from Operations – Changes in Working Capital) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

CFO pre-WC - Dividends / Debt

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Debt / Capitalization or Regulated Asset Value

(Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) / (Shareholders' equity + minority interest + deferred taxes + goodwill write-off reserve + Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) or RAV

Appendix E: Industry Overview

The electric and gas utility industry consists of companies that are engaged in the generation, transmission, and distribution of electricity and/or natural gas. While many utilities remain vertically integrated with operations in all three segments, others have functionally or legally unbundled these functions due to legislatively mandated market restructuring or other deregulation initiatives and may be engaged in just one or two of these activities.

The **generation** of electricity is the first step in the process of producing and delivering electricity to end use customers and typically the most capital intensive, with the largest portion of the industry's assets consisting of generating plants and related hard assets. Electricity is generated from a variety of fuel sources, including coal, natural gas, or oil; nuclear energy; and renewable sources such as hydro, wind, solar, geothermal, wood, and waste.

Transmission is the high voltage transfer of electricity over long distances from its source, usually the location of a generating plant, to substations closer to end use customers in population or industrial centers. Although many utilities own and operate their own transmission systems, there are also several independent transmission companies included in this methodology.

The **distribution** of electricity is the process whereby voltage is reduced and delivered from a high voltage transmission system through smaller wires to the end-users, which consist of industrial, commercial, government, or retail customers of the utility. Most of the utilities covered by this methodology are engaged to some degree in the distribution of electricity through "poles and wires" to their end customers. The distribution of natural gas entails the transport of gas from delivery points along major pipelines to customers in their service territory through distribution pipes.

Regulation Plays a Major Role in the Industry

Because of the essential nature of the utility's end products (electricity and gas), the public policy implications associated with their provision, the demands for high levels of reliability in their delivery, the monopoly status of most service territories, and the high capital costs associated with its infrastructure, the utility industry is generally subject to a high degree of government regulation and oversight. This regulation can take many forms and may include setting or approving the rates or other cost recovery mechanisms that utilities charge for their services (revenue), determining what costs can be recovered through base rates, authorizing returns that utilities earn on their investments, defining service territories, mandating the level and reliability of electricity and gas service that must be provided and enforcing safety standards. From a credit standpoint, the regulators' ability to set and control rates and returns is perhaps the most important regulatory consideration in determining a rating.

In the U.S., the most important utility regulator for most companies is the individual state agency generally known as the Public Utility Commission or the Public Service Commission. The commissions are comprised of elected or appointed officials in each state who determine, among other things, whether utility expenditures are reasonable and/or prudent and how they should be passed on to consumers through their utility rates. While some states have legislatively mandated certain market restructuring or deregulation initiatives with regard to the generation segment of their electricity markets, the majority of states remain fully regulated, and some states that had deregulated are in the process of "re-regulating" their electricity markets.

The key federal agency governing utilities in the U.S. is the Federal Energy Regulatory Commission (FERC), an independent agency that regulates, among other things, the interstate transmission of electricity and natural gas. The FERC's responsibilities include the approval of rates for the wholesale sale and transmission of electricity on an interstate basis by utilities, power marketers, power pools, power exchanges, and independent system operators. The Energy Policy Act of 2005 increased the FERC's regulatory authority in a wide range of areas including mergers and acquisitions, transmission siting, market practices, price transparency, and regional transmission organizations.

In Europe, following the implementation of specific policies relating to the liberalization of energy supply within the European Union (EU), the electric utility sector has been evolving toward a model targeting complete separation between network activities, regulated in light of their monopoly nature, and supply and production of energy, fully liberalized and hence unregulated. As a result of this process, most Western European utilities currently operate either as fully regulated entities in the networks segment, or largely unregulated integrated companies (albeit some may still maintain some regulated network activity), and are therefore excluded from the scope of this methodology. Nevertheless, there are countries in Europe where regulatory evolution and transition to competition remain at an earlier stage (Central and Eastern European countries and the Baltic states in particular) and/or are characterized by the remoteness and isolation of their systems (the islands in the Azores and Madeira regions for example). In these countries, Governments and/or Regulators maintain greater influence on the bulk of the utilities' revenues, thus supporting their inclusion in this methodology.

In Japan, regulation has been an important positive factor supporting utility credit quality. Japan's regulator makes the maintenance of supply its primary policy objective, followed in priority by environmental protection and finally, allowing market conditions to work. This approach preserves the utilities' integrated operations and makes them responsible for final supply to users in the liberalized market. The Japanese government is gradually deregulating the utility industry and expanding the liberalized market. However, the pace of deregulation has been moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of generation supply security.

In Australia, stable and predictable regulatory regimes continue to underpin the investment-grade characteristics of the sector. So far, regulators – which operate independently from the governments – have not adopted an aggressive stance to revenues and returns as they seek a balance between: appropriate returns for utilities; ongoing incentives for network investments; and appropriate prices for consumers. The supportiveness of the regimes will become increasingly important over the medium term as the sector undertakes investments to expand network capacity and replace ageing assets to meet rising demand.

In Asia Pacific (ex-Japan), regulation of electric utilities is overseen by government regulatory bodies in their respective countries. As such, the stability and regulatory framework can vary to a large extent by country with a few utilizing automatic cost pass through mechanisms while the majority operate with ad hoc tariff adjustments. However, power security remains a key policy objective and regulators continue to seek to ensure stability in regulatory and operating environments. Such regulatory environments are critical to attracting investments for both privatizations and for funding expanding electricity projects. Reform of the power industry in Asia remains slow paced and competition is well contained. Regulators have shown that they will reform in a prudent manner and allow tariff adjustment to minimize any material negative impact on the credit profiles of their power utilities. Such a supportive approach enhances stability and provides a stable regulatory regime which in turn remains a key driver in supporting the cash flows of Asia Pacific (ex-Japan) utilities.

In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies. Accordingly, the transparency and stability of regulation and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory frameworks in each jurisdiction are well established and there is a high expectation of timely recovery of cost and investments. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the U.S. Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors, to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes. As a result of the relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers.

In Latin America, there is a perceived lower level of regulatory supportiveness than in other regions. In Argentina, although the generation industry is deregulated, the government continues to intervene in the process of setting prices and tariffs. In addition, collections from sales to the spot market have only been partial and have depended on the government's discretion. Moody's views the current regulatory framework as a relatively high risk factor given the government's interference, the unclear regulations, the lack of support for the companies' profitability, and the lack of incentives for much needed long-term investment. Brazil's power generation companies could also be affected by unfavorable regulatory decisions, since about 75% of its electricity currently goes to the regulated market, but Moody's last year noted improvements in Brazil's regulatory environment, which led to several issuer upgrades. Brazil's regulatory model provides a more supportive environment for acceptable rates of return since the current rules for electric utilities are more transparent and technically driven. Nonetheless, there is a lower assurance of timely recovery of costs and investments in Brazil since the new framework has not yet experienced the stress of high inflation, exchange rate devaluation or electricity rationing. Recent distribution tariff review reductions have typically been in the high-single-digit range, which is considered modest, particularly compared to Moody's rated issuers in El Salvador (14% reduction) and Guatemala (45% reduction) both of which led to downgrades last year. The regulatory framework in Chile, in Moody's opinion, comes closest to the United States in terms of regulatory supportiveness.

Appendix F: Key Rating Issues Over the Intermediate Term

Global Climate Change and Environmental Awareness

Electric and gas utilities will continue to be affected by growing concerns over global climate change and greenhouse gas emissions, which are particularly important in the electricity generation segment which continues to rely on a large number of coal and natural gas fired power plants. There have been significant increases in environmental expenditure estimates among utilities with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. Utilities may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants has been cancelled as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to higher coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

While the global recession may have reduced electric demand in certain regions in the short-term, longer-term worldwide demand for electricity is expected to continue to grow and many utilities will incur substantial capital expenditures for new generation, as well as for upgrades and expansions to transmission systems. In the U.S., the Edison Electric Institute projects annual capacity additions among investor-owned utilities to increase to over 15,000 megawatts (MW) in 2009 compared with less than 6,000 MW in 2006. Some of the new plants announced include large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years. In Indonesia, the Fast Track program calls for the addition of 9,000 MW of coal-fired power plants while India plans to build eight ultra-mega power projects (each under 4,000 MW). Similar large nuclear plants are being constructed worldwide in countries as diverse as Bulgaria, China, India, Russia, South Korea, Taiwan and Ukraine. Because of this construction boom, international demand for certain construction materials, plant components and skilled labor has driven up the cost of new nuclear. More recently, the global economic slowdown may relieve some of this cost pressure.

Political and Regulatory Risk

As the utility industry faces higher operating costs, rising environmental compliance expenditures, large capital expenditures for new generation, as well as fuel and commodity price risks, the need for rate relief and other regulatory support will continue to be a key rating factor. In the U.S., political intervention in the regulatory process following particularly large rate increase requests increased risk and negatively affected the credit ratings of utilities in Illinois and Maryland in recent years. In Europe, rising electricity prices two years ago resulted in widespread criticism of utilities in several countries, increasing regulatory and political risk for some of them. In Australia, the transition from state based regulation to a national regulatory framework could pose a moderate level of uncertainty to current regulatory thinking over the longer term. In Asia Pacific (ex-Japan) and Latin America, the governments face political pressure regarding tariff adjustments given their need to balance socio-economic targets and inflationary concerns against the objective of ensuring reliable electricity supply over the long term.

Economic and Financial Market Conditions

Although electric and gas utilities are somewhat resistant (although not immune) to unsettled economic and financial market conditions due partly to the essential nature of the service provided, a protracted or severe recession could negatively affect credit profiles over the intermediate term in several ways. Falling demand for electricity or natural gas could negatively impact margins and debt service protection measures. Poor economic conditions could 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, constrained capital market conditions could severely limit the availability of credit necessary to finance needed capital expenditures, or make such financing plans more expensive.

Appendix G: Regional and Other Considerations

Notching Considerations - Structural Subordination and Holding Company Ratings

Utility corporate structures often include multiple legal entities within a single consolidated organization under an unregulated parent holding company. The holding company typically has one or more regulated operating subsidiaries and may have one or more unregulated subsidiaries as well. Most utility families issue debt at several of these legal entities within the organizational family including the parent holding company and the utility subsidiaries. In such cases, our approach is to assess each issuer on a standalone basis as well as to evaluate the creditworthiness of the consolidated entity. We also consider the interdependent relationships that may exist among affiliates and the degree to which a management team operates its utility subsidiaries as a system. We then assess the degree of legal and regulatory insulation that exists between the generally lower-risk regulated entities and the generally higher-risk unregulated entities.

The degree of notching (or rating differential) between entities in a single family of companies depends on the degree of insulation that exists between the regulated and unregulated entities, as well as the amount of debt at the holding company in comparison to the consolidated entity. If there is minimal insulation or ring-fencing between the parent and subsidiary and little to no debt at the parent, there is typically a one notch differential between the two to reflect structural subordination of the parent company debt compared to the operating subsidiary debt. If there is substantial insulation between the two and/or debt at the parent company is a material percentage of the overall debt, there could be two or more notches between the ratings of the parent and the subsidiary.

U.S. Securitization

Since the late 1990s, legislatively approved stranded cost and other regulatory asset securitization has become an increasingly utilized financing technique among some investor-owned electric utilities. In its simplest form, a stranded cost 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. Securitizations were originally done to reimburse utilities for stranded costs following deregulation, which was primarily related to the actual lower market values of the legacy generation compared to its book value. More recently, securitizations have been done to reimburse utilities for storm restoration costs following two active hurricane seasons in the U.S. in 2004 and 2005, with additional securitizations planned following an active 2008 hurricane season, as well as for environmental equipment. In 2007, Baltimore Gas & Electric used securitization to fund supply cost deferrals. Securitization could also be used to help fund the next generation of nuclear plants to be built in the U.S.

Although it often addresses a major credit overhang and provides an immediate source of cash, Moody's treats securitization debt of utilities as being on-credit debt. In calculating balance sheet leverage, Moody's treats the securitization as being fully recourse to the utility as accounting guidelines require the debt to appear on the utility's balance sheet. In looking at cash flow coverages, Moody's analysis focuses on ratios that include the securitized debt in the company's total debt as being the most consistent with the analysis of comparable companies. Securitizations also entail transition or other charges on ratepayer bills that may limit a utility's flexibility to raise rates for other reasons going forward. While our standard published credit ratios include the securitization debt, we also look at the ratios without the securitization debt and cash flow in our analysis, to distinguish this debt and ensure that the benefits of securitization are not ignored.

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

Strong levels of government ownership dominate Asia Pacific (ex-Japan) power utilities and remain one of their key rating drivers. The current majority state ownership levels are expected to remain largely unchanged for the near to medium term, thereby providing rating uplift to a majority of the government-owned Asia Pacific (ex-Japan) utilities under the Joint Default Analysis methodology.

Appendix H: Treatment of Power Purchase Agreements ("PPA's")

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, or to fix the cost of power. While Moody's regards these risk reduction measures positively, some aspects of PPAs may negatively affect the credit of utilities.

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 debt service and are made irrespective of whether the utility requires 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 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 analyzed by Moody's as PPAs.[4]

Factors determining the treatment of PPAs

Because PPAs have a wide variety of financial and regulatory characteristics, each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the 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. Factors which determine where on the continuum Moody's treats a particular PPA are as follows:

- Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's 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 Moody's regards 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, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- Price considerations: The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it

[4] When take-or-pay contracts, outsourcing agreements, PPAs and other rights to capacity are accounted for as leases under US GAAP or IFRS, they are treated by Moody's as such for analytical purposes.

does not require it for its own customers, 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 when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may 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. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totaled 42.0% of its operating costs in FY2008. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.

- 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. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.

- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's debt, in the same way as other off-balance sheet items.[5]

- Accounting: From a financial reporting standpoint, very few PPA's have thus far resulted in IPP's being consolidated by the off taker. Similarly, very few PPA's are treated as lease obligations. Due to upcoming accounting rule changes[6], however, coupled with many contracts being renegotiated and extended over the next several years, we expect to see an increasing number of projects being consolidated or PPA's accounted for as leases on utility financial statements. Many of the factors assessed in the accounting decision are the same as in our analysis, i.e. risk and control. However, our analysis also considers additional factors that the accountants may not, such as the ability to pass through costs. We will consider the rationale behind the accounting decision and compare it to our own analysis and may not necessarily come to the same conclusion as the accountants.

Each of these factors will be weighed by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods of accounting for PPAs in our analysis

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total debt obligations for the utility using one of the methods discussed below.

- 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, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the debt obligations of the utility. In the event operating costs are consolidated, we will attempt to deconsolidate these costs from a utility's financial statements.

- 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 be quantified otherwise due to limited information.

[5] See "The Analysis of Off-Balance Sheet Exposures – A Global Perspective", Rating Methodology, July 2004.
[6] SFAS 167 "Amendments to FASB Interpretation No. 46(r)" will be effective Q1 2010.

- Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be 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 Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility 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. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the effect of the PPA on the credit of the utility.

Moody's Related Research

Industry Outlooks:

- U.S. Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U.S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)

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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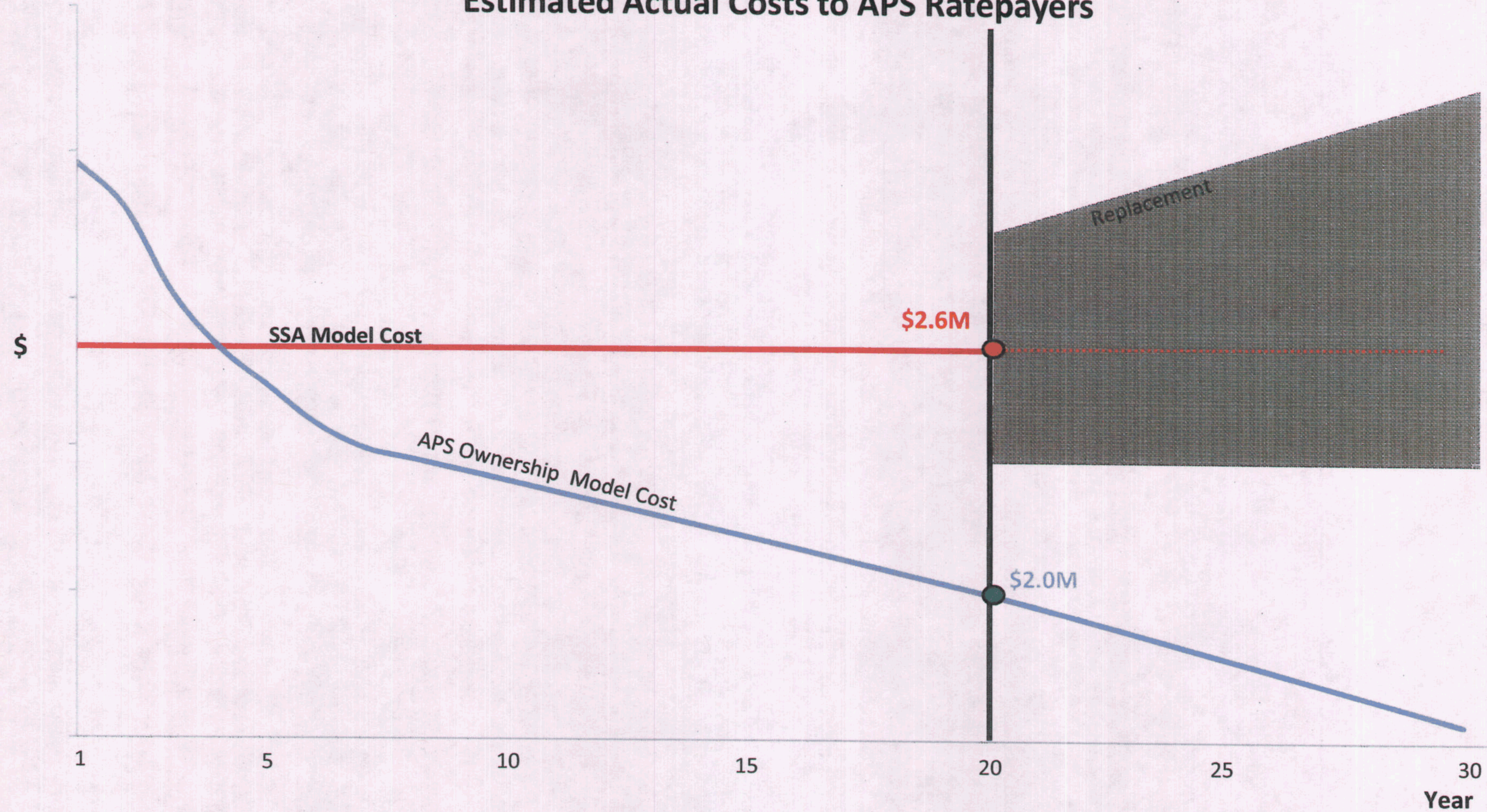
Moody's Investors Service

EXHIBIT
APS-2
ADMITTED

Schools and Government Program
Estimated Actual Costs to APS Ratepayers



1. Assumes a 350kW PV fixed axis system installation.

2011 RES Implementation Plan Marketing Budget (Approved December 2010)	
Commitments to Commission Approved Initiatives	
Qualified Solar Installer Program/TSI	*$625,000*
APS Advertising Support of Installers (Co-op)	*$560,000*
Solar Homes Program	*$450,000*
Residential Financing Incentives	*$70,000*
IT Transaction Platform and Customer Tools	*$185,000*
Arizona Goes Solar Website	*$40,000*
Arizona Solar Challenge - SmartPower	*$740,000*
Committed Outreach Initiatives	*$210,000*
Customer Research	*$75,000*
Sub-total	**$2,955,000**

Customer Education and Industry Support	
Sub-total	**$395,000**

Awareness Building/Advertising	
Sub-total	**$950,000**

Total	**$4,300,000**

EXHIBIT
tabbies
APS-3
ADMITTED

2011 RES Implementation Plan
RDC&I Budget (Approved December 2010)

Flagstaff Initiatives	
High Penetration Solar Deployment Study Support	*$100,000*
Flagstaff Energy Storage Demonstration Project	*$500,000*
Solar Water Heating Impact Study	*$50,000*
PV Variability/Intermittency Study (Completion)	*$50,000*
Solar Cost Integration Study	*$250,000*
Sub-total	**$950,000**

Other Funded and Committed Projects	
Solar Augmentation Natural Gas Combined Cycle Study	*$90,000*
AZ Smart (ASU)	*$250,000*
Sub-total	**$340,000**

Planned Research Partnerships	
Department of Energy Studies and Other IndustryResearch	*$210,000*
Sub-total	**$210,000**

Total	**$1,500,000**

Arizona Corporation Commission
DOCKETED

NOV 10 2010

DOCKETED BY

OPEN MEETING

MEMORANDUM

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2010 NOV 10 P 4: 49

AZ CORP COMMISSION
DOCKET CONTROL

EXHIBIT
S-1
ADMITTED

ORIGINAL

TO: THE COMMISSION

FROM: Utilities Division

DATE: November 10, 2010

RE: ARIZONA PUBLIC SERVICE COMPANY - APPLICATION FOR APPROVAL OF SCHOOLS AND GOVERNMENT RENEWABLE ENERGY PROGRAM (DOCKET NO. E-01345A-10-0166) AND APPLICATION FOR APPROVAL OF ITS RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN FOR 2011 (DOCKET NO. E-01345A-10-0262)

Background

On April 29, 2010, Arizona Public Service Company ("APS" or "Company") filed its application for approval of its schools and government renewable energy program, pursuant to Decision No. 71448. On July 1, 2010, APS filed its application for approval of its 2011 Implementation Plan pursuant to the Renewable Energy Standard and Tariff ("REST") Rules. On July 26, 2010, the two dockets were consolidated. On October 13, 2010, APS submitted a Supplemental Filing.

The APS REST Implementation Plan 2011 to 2015

The APS REST Implementation Plan 2011 to 2015 is a five-year plan describing how APS intends to comply with the REST requirements. In a separate document, Attachment B of the APS application, APS has filed its Distributed Energy Administration Plan ("DEAP") describing how APS intends to meet the annual Distributed Renewable Energy Requirement.

APS had originally estimated that the cost for full compliance with the REST Rules would total $96.4 million in 2011. This is an increase of about 11 percent over 2010's $86.7 million. Budget details are given in Table 1 below.

Included in the Supplemental filing was an update on 2010 RES incentive funding and a proposal for improving the wholesale distribution interconnection process for renewable energy projects. The impact of increasing the number of renewable power interconnections on APS' distribution system affects safety, power quality, and reliability.

APS is proposing a system to improve and streamline the interconnection process by identifying the most viable projects. Three levels of increasingly detailed studies would be performed at the developer's request, and would identify technical issues earlier in the development process. APS would charge fees associated with requested studies, consistent with Commission Decision No. 69674. The first two optional studies, a Feasibility Study and a

System Impact Study, would cost the developer $15,000. The third study, a Facilities Study, would be required and cost the developer a fee of $100 per hour with a $55,000 deposit. All fees would be applied to the RES budget, offsetting resources required for the services. APS included modifications to the proposed APS RES adjustor, to reflect this.

Staff has reviewed the APS proposed Wholesale Distribution Interconnection Process. Staff has reviewed the process improvements and proposed fee schedules. Staff believes it is necessary for APS to analyze an interconnection's impact on its distribution system. The proposed fees for APS' engineering expertise are reasonable. However, new fees should be on a Tariff Schedule.

In the Supplemental Filing, APS recalculated the timing for expected start-up of various non-residential performance based incentive ("PBI") projects, Powerful Communities projects, and AZ Sun projects. This recalculation resulted in a downward revision of APS' budget estimates for 2011, lowering the APS budget request for 2011 by $3.9 million. This resulted in a revised budget request of $92.5 million compared to original proposed budget amount of $96.4 million.

As part of the Supplemental Filing, APS has revised the Schools and Government Rate Schedule in order to allow the schedule to be used in conjunction with a new schools time-of-use rate schedule that was approved by the Commission in August 2010.

Finally, in the Supplemental Filing, APS submitted revisions to the Distributed Energy Administration Plan. Included was a clarification that Rapid Reservation requests will not be counted as part of the maximum 600 reservations that would be accepted in the first three funding cycles. The Rapid Reservation funds instead would come from the fourth funding cycle.

APS is now requesting increases in its adjustor rate to collect $86.5 million; $6.0 million is collected in base rates to reach the total of $92.5 million. This budget is detailed in Table 1. Staff is proposing a budget of $96.4 million.

REST adjustor rates would increase about 17 percent and are shown below in Table 2.

Table 3 presents a variety of typical Customer types with the monthly RES surcharge amounts each would pay.

Table 1
APS 2011 REST Budget

Line No	**$ Millions**	*2010*	*APS Original*	*APS Adjusted*	*Staff Proposed*
1	Renewable Generation				
2	Purchases and Generation	8.5	17.0	18.8	18.8
3	Administration	1.3	1.5	1.5	1.5
4	Implementation	1.1	1.5	1.5	1.5

Table 1- APS 2011 REST Budget (Cont'd)					
5	***Total Renewable Generation Contracts and O/M***	10.9	20.0	21.8	21.8
6	Estimated Green Choice/Rollover Offset Credit	-0.4	-3.8	-0.6	-0.6
7	***Total Renewable Generation***	10.5	16.2	21.2	21.2
8	***Customer-Sited Distributed Energy***				
9	Existing Contracts and Commitments				
10	Distributed Energy RFP		1.1	1.1	1.1
11	Innovative Technologies		0.3	0.3	0.3
12	Existing Production-based Incentives	16.6	15.3	7.6	7.6
13	Flagstaff Community Power Project		0.4	0.4	0.4
14	Wholesale Distributed Energy		0.2	0.2	0.2
15	ARRA Projects/Incentives		1.2	1.2	1.2
16	2010 Residential Incentive Commitment		0.9	1.7	1.7
17	***Total Existing Contracts and Commitments***	16.6	19.4	12.5	12.5
19	*New Incentives and Commitments*				
20	Residential Up-front	44.1	34.0	34.0	39.0
21	Schools and Government Buildings		7.3	7.3	6.8
22	Non-Residential Up-front	2.0	2.0	2.0	2.0
23	Production Based Incentives		2.1	0.3	0.3
24	Powerful Communities		0.4	0.2	0.2
25	***Total New Incentives and Commitment***	46.6	46.3	44.3	48.8
26	Total Incentives and Commitments	63.2	65.7	56.8	61.3
27	*Non-Incentive Distributed Energy*				
28	Customer Self-Directed	0	0	0	0
30	Administration	1.6	1.4	1.4	1.4
31	Implementation	3.1	3.7	3.7	3.7
32	Information Technology	1.5	2.0	2.0	2.0
33	Marketing & Outreach	4.8	5.4	5.4	5.3
34	***Total Non-Incentive*** Distributed Energy	11.0	12.5	12.5	12.4
35	***Total Customer Sited*** Distributed Energy ***(line 26 + line 34)***	74.2	78.2	69.3	73.7
36	***Research, Development, Commercialization, & Integration***	2.0	2.0	2.0	1.5
37					
38	**Total RES Budget**	86.7	96.4	92.5	96.4

Table 2
APS 2011 REST Adjustor Rates

	2010	*APS Original*	*APS Adjusted*	*Staff Proposed*
Rate per kWh	$0.0086620	$0.0101320	$0.0096630	$0.0101320
Residential Monthly Cap	$3.46	$4.05	$3.87	$4.05
Small Non-residential Monthly Cap	$128.70	$150.53	$143.56	$150.53
Large Non-residential Monthly Cap	$386.10	$451.60	$430.67	$451.60

Table 3
Customer Impact of Proposed REST Adjustor Rates

		kWh per Month	*2010*	*APS Original*	*APS Adjusted*	*Staff Proposed*
Customer Types and Monthly Costs						
1	Residence	>= 400	$3.46	$4.05	$3.87	$4.05
2	Dentist Office	2,000	$17.32	$20.26	$19.33	$20.26
3	Hairstylist	3,900	$33.78	$39.51	$37.69	$39.51
4	Department Store	170,000	$128.70	$150.53	$143.56	$150.53
5	Retail Video Store	14,400	$124.73	$145.90	$139.15	$145.90
6	Large Hotel	1,067,100	$128.70	$150.53	$143.56	$150.53
7	Large Building Supply/Hardware	346,500	$128.70	$150.53	$143.56	$150.53
8	Hotel/Motel	27,960	$128.70	$150.53	$143.56	$150.53
9	Fast Food	60,160	$128.70	$150.53	$143.56	$150.53
10	Large High Rise Office Bldg	1,476,100	$128.70	$150.53	$143.56	$150.53
11	Supermarket	233,600	$128.70	$150.53	$143.56	$150.53
12	Convenience Store	20,160	$128.70	$150.53	$143.56	$150.53
13	Hospital (< 3 MW)	1,509,600	$128.70	$150.53	$143.56	$150.53
14	Hospital (> 3 MW)	2,700,000	$386.10	$451.60	$430.67	$451.60
15	Copper Mine	72,000,000	$386.10	$451.60	$430.67	$451.60
16	Mall (>3MW)	1,627,100	$386.10	$451.60	$430.67	$451.60

Renewable Generation

For year 2011, APS indicates that it would own and operate approximately 6 MW of solar capacity. In addition, APS has entered into power purchase agreements for 228 MW of wind, geothermal, and biomass/biogas renewable generation capacity, and expects 20 MW from its Small Generation Request for Proposal ("RFP") and 33 MW from AZ Sun projects. This totals 287 MW of renewable generation as described in detail in Exhibit 3B of Attachment A in the APS Supplemental filing.

The expected annual MWh of generation from existing contracts and planned generation is shown in Exhibit 3A of Attachment A of the APS plan. The estimate for existing renewable generation is 851,805 MWh in 2011.

Schools and Government Program

Decision No. 71275 requires APS to offer proposals which could increase distributed energy ("DE") participation for governmental and schools customers. APS will offer these customers performance-based incentives for installation of qualifying non-residential RES facilities as part of a Schools and Governmental Program.

A Schools and Government Program was filed on April 29, 2010 (E-01345A-10-0166). With that filing, APS is seeking approval of a new program for on-site renewable energy for schools and governmental institutions that would substantially reduce or eliminate up-front costs for solar energy.

To eliminate up-front costs that would normally be incurred by schools or governmental institutions when installing solar facilities, APS is proposing three customer options to eliminate or reduce up-front costs for schools and governmental institutions:

1) third-party ownership
2) utility-ownership option
3) solar daylighting bank financing option

With the Third-Party Ownership option, the third-party owners traditionally require no up-front payment from the customer, instead the customer pays the third-party owner for the lease of the system equipment and the customer benefits from the energy produced by the on-site PV system.

For the Utility Ownership option, APS is proposing to make available a utility ownership option for the proposed Schools and Government Program. To maximize opportunities for solar installers and developers, no more than one-half of the installed PV capacity would be eligible under the utility-ownership option. APS proposes PV system installations utilizing the same utility ownership arrangement that is being offered in the recently approved Community Power Project - Flagstaff Pilot program. PV systems would be connected directly to the distribution grid on the customer's property, and the customer would be billed for a portion of their usage equivalent to the output of the PV system, with a specific rate designed to reflect the benefits of a customer-owned renewable resource, i.e., a proposed School and Government Solar Program Rider Rate Schedule. This solar charge would remain unchanged for the twenty-year term of the rate schedule.

Renewable energy from the utility-owned solar systems would not count toward the RES distributed energy requirements; rather, they would be applied to the Company's overall RES requirement. APS is proposing that the cost of ownership (or revenue requirement) for this option would be recovered through the RES adjustor until the investment is included in base rates or other recovery mechanism.

In the Solar Daylighting Project Financing option, the costs associated with solar daylighting installations are significantly less than that of PV and solar thermal installation costs and school districts and governmental institutions have expressed a preference to purchase and own these systems. For customers interested in a financing option to install solar daylighting, APS will partner with National Bank of Arizona to offer customers an option that eliminates up-front cost. Solar daylighting projects under the proposed Schools and Government Program would be eligible for a five to seven year operating lease, with the option to purchase the system at fair market value at the end of the lease term.

In its Supplemental Filing, APS revised the Schools and Government Rate Schedule ("SGSP"). In Decision No. 71871 the Commission adopted a new optional time-of-use ("TOU') rate applicable to K- 12 schools, which will provide daily and seasonal price signals to encourage load reductions during peak periods. In this docket, APS has revised the Schools and Government Rate Schedule (Exhibit D) to incorporate the changes necessary to allow the schedule to be used in conjunction with the new schools TOU rate schedules.

Rate Schedule SGSP is shown in Exhibit H of APS' filing. As indicated, its design is the same as the Community Power Project - Flagstaff Pilot program, with a solar charge ranging from 7.3 to 9.3 ¢/kW, depending on the base service retail rate schedule. For School or Governmental customers on time-of-use rates, the solar energy would be netted against on-peak, shoulder-peak, or off-peak time periods according to an allocation based on typical usage. The solar charge would remain unchanged for the twenty-year term of the rate schedule.

Staff has reviewed the Revised Rate Schedule SGSP. Staff's analysis finds that SGSP is a properly-designed rate which allows the benefits of renewable energy to flow back to the customers in a reasonable manner.

Feed-In Tariff Programs

In January 2010, the Commission issued a Notice of Inquiry to solicit input on specific issues related to developing a potential Feed-In Tariff ("FIT") program, which is a transaction mechanism that is designed to encourage the targeted deployment of renewable energy resources. Under a FIT, an electric utility pays a renewable energy developer for both energy and renewable energy credits ("RECs") at an agreed-upon and sometimes predetermined rate for an extended number of years under a standardized commercial agreement.

Well-designed FIT policies could offer additional methods for promoting the development of renewable energy resources. APS is proposing two programs aimed at different renewable energy market segments that embrace FIT principals: 1) Powerful Communities, a wholesale DE FIT program that targets customer groups that have had limited participation in RES programs; and 2) a Small Generator Standard Offer Program that would provide energy credited towards APS's renewable generation requirements. Each of the programs is designed to extend over a three-year period.

Powerful Communities (Wholesale Distributed Energy FIT)

The proposed Powerful Communities FIT program targets market segments that currently have a more difficult time accessing the incentive funding through the current RES programs, specifically low-income housing entities, homeowner associations, multi-tenant facilities (residential and commercial), and not-for-profit charitable organizations. PV facilities that are between 30 kilowatts and 200 kilowatts and are planned to be operational within 12 months would be eligible for this program. APS is proposing that the program be limited to 2 megawatts of total annual procurement in each year of the program, for a total of 6 megawatts. This limit to the program size is proposed as a way to manage the amount of customer-subsidized developer incentives paid annually. Participants will be awarded on a first-come, first-served basis. The Company is proposing a standard fixed price offer for the Powerful Communities FIT Program of $0.195/kilowatt-hour for the production output of the system under a 20-year agreement. The program has an estimated annual cost of $375,000, and a lifetime commitment for these 20-year contracts of approximately $22.5 million.

Small Generator Standard Offer Program

The Small Generator Standard Offer would focus on four aspects of smaller projects:

1. Advanced approval for the program budget,
2. A predetermined budget and plans to fully commit a portion of the budget,
3. Pre-scheduling of future project solicitations, and
4. Proposed transactional enhancements.

Renewable resource technology within the range of 2 to 15 megawatts would be eligible for this program. The program would have a $10 million budget over a three-year deployment. APS forecasts this program has the potential to provide approximately 200 gigawatt-hours annually once fully deployed.

The Company believes these budgetary and scheduling commitments will be an important indicator to the developer community of APS's intent to procure and install small renewable energy projects.

Staff recognizes that there is significant interest in feed-in tariffs. However, Staff believes that the current workshop activities related to feed-in tariffs should be allowed to run their course before utilities implement feed-in tariffs, even on a pilot basis, given the significant financial commitment even a one year pilot program would entail. Staff recommends against approval of the proposed feed-in tariff pilot program as part of the 2011 REST implementation plan for APS.

Distributed Energy

For the 2011 Plan, APS proposes to increase its PBI lifetime commitment by $100 million to $670 million.

The most significant changes to the APS REST Plan for 2011 relate to the phenomenal demand experienced in 2010 for residential distributed photovoltaic systems. Due to the unprecedented demand seen in 2010 and the anticipated continuation of residential demand in 2011, APS has proposed some major changes to its residential distributed energy program.

In 2010, when 75 percent of the APS 2010 residential incentive budget was allocated in the first quarter of 2010, the Commission stepped in, lowering the residential PV incentive from $3 per watt to $2.15 per watt and finally to $1.95 per watt (Decision No. 71686, dated April 30, 2010).

The residential demand continued at an accelerated rate, causing the Commission to shift funds from other budget priorities to the residential program and to lower the residential PV incentive to $1.75 per watt (Decision No. 71913, dated September 28, 2010). This incentive level reduction and an allocation from the 2011 budget were used to help APS reduce the queue of customers desiring residential incentives.

In Decision No. 71913, the Commission authorized APS to institute an incentive step-down mechanism that is triggered by the volume of residential systems installed under the program. The Commission also ordered that the last quarter of 2010 become Funding Cycle 1 of 2011 for the purpose of allocating a portion of the 2011 REST budget to residential projects waiting in the queue for REST incentives.

Based on the problems experienced in 2010 and feedback from the solar industry stakeholders, APS proposed a redesign of the incentive system. The redesign includes a clear delineation of proposed future reductions in incentives including pre-determined "step-downs", a specific allocation of funds for non-PV technologies, and specific funding cycles that would spread annual residential PV incentive funding over the entire budget year.

The automatic "step-down" mechanism for PV incentives would establish tranches of 1,200 grid-tied Distributed Energy applications, each providing incentives for approximately 8 MW of capacity.

Following the reservation of the first tranche at $1.75 per watt, APS proposes that the residential grid-tied PV incentive be decreased by $0.15 per watt to $1.60 per watt, reaching $1.45 per watt by the end of 2011. The first three tranches would have step-downs of $0.15 per watt, followed by three tranches with $0.10 per watt step-downs in future years. After the first six tranches, each additional tranche would step down $0.05 per watt.

Also included in APS' proposed changes is a new "rapid reservation" proposal that would allow APS to confirm upon receipt all PV applications that request incentives of $1.00 per watt or less.

In Decision Nos. 71686 and 71913, the Commission approved the funding of residential PV project applications received during the final quarter of 2010 with funds from the 2011 REST Plan. In its 2011 REST Plan, APS proposes to continue this approach where "For the purposes of this Plan, the first Funding Cycle of each Plan year occurs during the final quarter of the proceeding calendar year (e.g., Funding Cycle One of 2011 begins in October 2010)."

APS requests approval for the continuation of a specific allocation for non-PV residential projects. For 2011, this would be $6 million and would be for technologies such as solar space heating, solar water heating, geothermal applications and other eligible residential DE technologies.

APS proposes removal of the incentive cap of 50 percent of total residential system cost, and for thermal applications, the cap requiring a minimum 15 percent customer contribution. APS claims that the caps are no longer needed.

APS is proposing a new Customized Incentives for Home Builders program. It would provide predictable incentive levels and longer reservation periods in order to address the needs of production and custom home builders. In 2011, APS proposes PV incentives of $1.95 per watt and $0.50 per kilowatt-hour for solar water heaters. To accommodate builders' three-year sale/build cycles, the PV incentives would be reduced by $0.50 per watt after the first year, followed by $0.25 and $0.15 per watt reductions in following years. This program has a separate budget allocation.

The APS non-residential portion of the plan would increase its lifetime commitments to PBIs by $100 million in 2011.

APS noticed in 2010 that non-residential project demand for "medium projects" was greater than the demand for 'large projects." APS has proposed a change to allocate the 2011 funding more equally over various project sizes. The definition of "medium projects" would change to projects where the generator or inverter is rated at 200 kilowatts or less and "large projects" would be where the generator or inverter is greater than 200 kilowatts. Currently, that definition changes at 100 kilowatts.

APS proposed to eliminate the "10/20" PBI contract. This contract provides 10 years of PBI payments with a 20-year REC agreement. APS believes that the risk of an advance payment for future production is no longer warranted.

Based on stakeholder feedback, APS has proposed the elimination of the 60 percent cap on non-residential incentives.

Staff has reviewed the Distributed Energy Programs and changes as proposed by APS.

First, Staff agrees with APS that some form of market-driven trigger should be used to lower residential PV incentives. The lack of such a mechanism was a major reason that APS experienced the boom-bust problems in the residential PV market in 2010, where demand outstripped available funding and REST Plan procedures needed to be fixed by the Commission in both April and September.

Staff has proposed an Alternative Budget Trigger Mechanism. APS had its first incentive problem in the First Quarter of 2010 when 75 percent of the money for residential incentives was committed in the first three months of the year. Unfortunately, the APS-proposed trigger would not avoid a similar budget problem in 2011.

Staff's Alternative Budget Trigger Mechanism ties the reduction of incentives to budget *expenditures in* each quarter. If APS is ahead of schedule in committing PV incentive budget funds, the trigger will activate an incentive reduction. If the market is sluggish, no incentive reduction would take place. So, for instance, if 30 percent of the 2011 residential PV budget is committed on or before March 31, 2011, the incentive would drop by $0.15 from $1.75 to $1.60. If only 25 percent of the budget is committed by March 31, 2011, the incentive would stay at $1.75.

STAFF'S ALTERNATIVE BUDGET TRIGGER MECHANISM

	First Trigger	Second Trigger	Third Trigger	Fourth Trigger
Trigger	If 30% of 2011 PV Incentive Budget is committed by APS on or before March 31, 2011	If 52% of 2011 PV Incentive Budget is committed by APS on or before June 30, 2011	If 77% of 2011 PV Incentive Budget is committed by APS on or before September 30, 2011	If 100% of 2011 PV Incentive Budget is committed by APS on or before December 31, 2011
New Incentive Level	$1.60 / Watt	$1.50 / Watt	$1.45 / Watt	$1.40 / Watt

Staff recommends that the Commission replace the APS-proposed MW trigger mechanism for residential PV incentives with the Staff-proposed Alternative Budget Trigger Mechanism as described herein.

The APS proposal to make the first Funding Cycle of each Plan year occur during the final quarter of the preceding calendar year causes Staff some concern. That concern relates to the fact that the funding for the first Funding Cycle will likely not have been approved by the October 1 start of the quarter. Since the Commission normally does not hear or approve REST Plans until November or December of each year, the budget for the next year, incentive levels, and other program procedures will still be in question on October 1st. With that caution in mind, Staff does not see a better alternative that would avoid problems in the normally hectic fourth quarter and therefore recommends approval of this approach for 2011 only. Since this approach was already approved for 2010 in Decision No. 71913 in September 2010, by the time the Commission considers the APS 2012 REST Plan, it will have some results from 2010 and 2011 to review to determine whether it is appropriate to continue this mechanism.

Staff agrees with the APS designation of $6 million in the budget for non-PV technologies. This is a good method to ensure that the residential program includes a variety of technologies, not just photovoltaics.

Staff recommends approval of the rapid reservation program offering $1 per watt for PV incentives. This is an excellent mechanism to reduce the cost of renewable kWh for APS and its customers.

Staff disagrees with APS on the removal of the incentive cap of 50 percent of the total system costs for residential systems. If, as APS claims, the declining cost of PV will make the caps unnecessary, there is no harm leaving them in place. If, however, in the future the costs of PV drop farther than the incentive levels, there may be a need for such a cap. Staff sees no compelling reason to remove the cap. Staff recommends that the caps remain in place at 50 percent for both residential and non-residential.

Staff supports the Customized Incentives for Home Builders program proposed by APS. Staff believes this program will encourage the installation of renewable energy by home builders and in turn promote the Commission's efforts to ensure that APS continues to provide reliable service at just and reasonable rates. Staff recommends approval of the Home Builder program as proposed.

Staff agrees with APS' change to the definitions of "medium projects" and "large projects" by moving the dividing line from 100 kW to 200 kW. Staff also recommends that APS' request to eliminate the "10/20" PBI contract be approved. There is sufficient market interest for the 10, 15, and 20-year contracts for APS to meet its REST goals. The "10/20" PBI contract is too risky for both APS and its ratepayers.

Staff disagrees with APS' request to remove the 60 percent cap on non-residential incentives. If "...the incentive programs offered by the Company have become sufficiently competitive to adequately drive available cost-reduction opportunities into projects receiving incentive funding" as APS claims, then there is no need to remove the cap. However, as indicated above, Staff recommends that the caps remain in place but be reduced to 50 percent for both residential and non-residential.

Staff disagrees with the APS reduction from $44.1 million to $34 million budgeted for residential up-front incentives. Although the reduction of incentive levels from $3 per watt to $1.75 per watt will have an impact on the market demand, there appears to be a continuing strong consumer demand for residential PV systems.

Staff believes that APS may have reduced the residential incentive budget too much. The economics of the residential PV incentive program are compelling. At an incentive of $1.75 per watt, APS provides incentives of $1,750 per kW of PV systems. Assuming that each kW of PV panels produce 1,700 kWh per year for 20 years, the cost to APS per delivered kWh is $0.0514 per kWh. The calculations are shown in Table 4.

Table 4
APS' Cost per kWh Resulting From Residential PV Incentives

<u>Incentive:</u>
$1.75 per watt = $1,750 per kW

<u>System output:</u> 1,700 kWh / kW/ year
(1,700 kWh/year) times 20 years = 34,000 kWh

<u>Cost per kWh:</u>
$1,750 divided by 34,000 kWh = $0.0514 per kWh

The economics of the residential PV incentives show that the residential kWh cost to APS is significantly lower (5.14 cents per kWh) than any other option in the REST Plan. The residential kWh cost to APS is much lower than the proposed Feed-in Tariff (at 19.5 cents per kWh), the proposed non-residential PBI incentives of 15.4 cents, 14.3 cents, or 13.8 cents or the cost per kWh from utility scale power purchase agreements that will likely range from 8 cents to 15 cents per kWh.

Faced with the favorable economics of residential PV incentives, Staff recommends an increase in the 2011 residential up-front incentives of $5 million to total $39 million in 2011 rather than the APS' proposed $34 million budget. Staff further recommends that one-half or $2.5 million of this additional funding be set aside to fund the rapid reservation program. Any of the $2.5 million in rapid reservation funds that have not been committed by APS by September 30, 2011, would revert to regular residential incentives for use on or after October 1, 2011.

This additional $5 million in residential up-front incentives would come from a combination of the $3.9 million reduction in the 2011 budget proposed by APS in its Supplemental Filing that was docketed on October 13, 2010, and an additional $1.1 million reduction in three parts of the revised APS budget. Staff proposes a $500,000 reduction in the proposed Schools and Government Program, an additional $500,000 reduction in the Research, Development, Commercialization and Integration budget, and a $100,000 reduction the Marketing and Outreach budget. Staff believes that APS can incorporate these budget changes and still meet its REST requirements. The reduction in the Schools and Government Program can be accomplished by shifting $500,000 of the 2011 portion of the three-year budget from 2011 to 2012. The $500,000 reduction in the Research, Development, Commercialization and Outreach budget can be accomplished by APS' prioritization of projects proposed. Finally, with long waiting lines for residential and non-residential distributed systems, APS can afford a slight reduction in its Marketing and Outreach Program. Staff proposes that the total 2011 budget remain as originally proposed by APS at $96.4 million, including the changes proposed by APS in its supplemental filing and the changes proposed by Staff in this memorandum.

Staff is concerned that APS has not reduced its non-residential PBI incentives in a manner commensurate with the reduction in cost of photovoltaic systems. Staff notes that in August of 2009, APS had enough non-residential projects in the queue to meet all of its non-residential DE requirements through 2011.

Since demand for non-residential grid-tied PV projects is still increasing, it appears that the incentives offered by APS are slightly higher than needed to meet APS' REST requirements. Therefore, Staff recommends that the APS proposed incentive for 10-year contracts be reduced from the proposed $0.154 per kWh to $0.14 per kWh. The proposed incentive of $0.143 per kWh for 15-year contracts should be reduced to $0.13 per kWh and the proposed $0.138 per kWh for 20-year contracts should be reduced to $0.125 per kWh.

Similarly, Staff recommends that the up-front incentive for small non-residential PV systems be reduced from $2.25 per watt to $1.75 per watt, which is comparable to the APS residential incentives.

The APS Distributed Energy Administration Plan

APS has proposed some modifications to its Distributed Energy Administration Plan. Due to Internal Revenue Service rulings, APS will be required to report incentive payments to customers on IRS Form 1099.

APS clarifies that the Rapid Reservation requests will not be counted as part of the maximum 600 reservations in the first three funding cycles, but will be accrued to the fourth funding cycle.

APS intends that customers' equipment meets the highest national safety and performance standards. APS is requiring new test standards for inverters, thin film solar modules, and crystalline silcon modules.

Solar daylighting projects will be exempt from submitting an energy savings and design report if the offsetting savings software that is used for the system design has been approved and validated by APS.

Non-residential active open-loop solar water heating systems will not be eligible for incentives, unless their technology or designs are proven to limit system degradation.

Solar providers will be required to provide APS with written notification of mergers or business name changes in order to facilitate the tracking of system installations.

APS has clarified the criteria for up-front incentives ("UFI") for both residential and nonresidential projects. Residential grid-tied PV UFIs are limited to 25 kilowatts. Non-residential projects with a total incentive of less than or equal to $75,000 are only eligible for UFI incentives.

Staff has reviewed the proposed changes to the APS Distributed Energy Administration Plan. The clarification on the Rapid Reservations not counting toward the quarterly 600-reservation limits should answer some of the industry concerns about the program. APS' requirement for new test standards for equipment should help improve the quality of equipment in the incentive program. Other administrative changes to the DEAP appear to be appropriate. Staff recommends that the changes be approved.

Large Distributed Energy Plants

In August 2008, APS issued an RFP for Distributed Energy Resources ("DE RFP"). APS received 22 distinct proposals. Winners were selected and contracts were signed between APS and winning bidders. As part of the APS 2010 REST Plan, two new transaction types were approved:

1. Customer Aggregation model. This allows the developer to phase-in projects over several years.

2. REC and Energy Contract model. The developer sites a PV system at a customer's facility and APS would purchase all of the energy and associated RECs generated by the system. APS and the customers would have a separate agreement for the customer to purchase all of the energy from the DE system.

Recently, there has been extensive discussion about setting a size cap for large distributed projects.

Staff has considered the suggestion of placing size caps on large distributed renewable systems. On a going forward basis, for projects with contracts being signed in the future, this is a possibility. However, Staff believes that attempting to place caps on winners of RFPs with signed contracts may set a bad precedent.

Placing caps on future large distributed energy systems can be done. However, doing so may cause an increase to the delivered cost per kWh. By setting a cap, bidders will lose the economies of scale advantage and this will result in higher bids.

Should the Commission decide to place size caps on future distributed energy projects, Staff would recommend a cap of 10 MW per developer. This should allow some economies of scale, while limiting the portion of the budget that will be captured by a single applicant.

Snowflake Biomass

In 2008, APS contracted with a biomass power plant in Snowflake, Arizona to purchase 60 percent of the plant's output. Earlier this year, the plant filed Chapter 11 and the other partner, Salt River Project, terminated its power purchase agreement ("PPA").

To maintain APS' renewable portfolio, APS has entered into a one-year contract to purchase all of the plant's output. This represents an additional ten megawatts. The terms are consistent with the original 2008 power purchase agreement.

Innovative Renewable Energy Project Initiative

The Innovative Renewable Energy Project Initiative is designed to facilitate the installation of technologies that are not specifically cost-optimized for the DE market. For example, PV panels may be installed in innovative configurations that produce a wide array of site specific and potential community benefits, but may be more expensive.

Through the Innovative Renewable Energy Projects Initiative, APS would seek to procure renewable resource installations designed to demonstrate innovative deployment opportunities and innovative technologies. The Company proposes to execute this program with the balance of the $25 million remaining from the approved lifetime commitment authorization for the DE RFP. Inasmuch as these projects are used to serve a specific customer, their energy will be applied to the appropriate DE target. If the resulting resources are not categorized as DE, their output will be applied to the overall APS renewable energy target.

Comments of Other Parties

The Arizona Solar Power Society ("ASPS") filed comments proposing increased spending on renewables. However, their backup calculations indicated a misunderstanding of how the REST Adjustor operates. ASPS presumed that all APS customers pay the maximum REST Surcharge, that is, the limits shown in Table 2. That is not correct.

Green Choice Solar filed two comment letters. The first letter disagreed with the APS Feed-In Tariff, and recommended a cap of 75 MW and a rate of $0.25 per kWh. Staff disagrees with the Green Choice Feed-In Tariff proposal. Staff is recommending no Feed-In Tariff be instituted at this time, and a tariff with Green Choice's rate and capacity could be even more costly than APS' proposal, increasing customer costs by as much as $32.5 million per year.

Green Choice's second letter criticized the shifting of PBI incentives from non-residential to residential customers. Green Choice recommended reservation fees to discourage applications for what it termed "dubious projects". Green Choice also recommended that the Schools and Government Program exclude any utility-ownership options. Staff believes an increased residential incentive budget is appropriate and as indicated above, the favorable economics of residential PV incentives warrant an increase in the 2011 residential up-front incentives of $5 million as Staff recommends. Staff does not disagree that a reservation fee could discourage "dubious" proposals, but does not have a recommendation for a fee configuration at this time. Staff does not agree with Green Choice that excluding utility-owned projects in the Schools and Government Program is wise. Financing is difficult, and utility ownership offers customers a way to install a renewable system should other financing options be unavailable.

Arizona Discount Solar filed a letter with concerns about poor communication between utilities and solar companies, and the exhaustion of funds for incentives. Staff believes that Arizona Discount's concerns have been addressed by Commission Decision No. 71913, dated September 28, 2010, which clarified certain incentive payments. APS' actions will also help, e.g., the solar web page information (http://arizonagoessolar.org/), the "trigger" reduction mechanism, and the lower per-watt incentive payments. Staff expects these measures will allow the Arizona solar market to move at a more reasonable and manageable pace.

Recommendations

Because APS' plan allows it to meet the Commission-approved REST requirements in 2011, Staff recommends that APS' 2011 REST Implementation Plan be approved with the Staff's recommended program and budget adjustments as presented herein. This Plan cost is $96.4 million, and it continues to meet full REST requirements.

Staff also makes the following recommendations:

1. That the RES Adjustor Rate be reset to $0.0101320 per kWh with monthly caps of $4.05 for residential customers, $150.53 for non-residential customers, and $451.60 for non-residential customers with demands of 3 MW or greater.

2. Approval of the APS request to make the First Funding Cycle of the 2012 Plan year occur during the final quarter of 2011. This would be a one-time only approval.

3. Staff recommends approval of the Staff Alternative Budget Trigger Mechanism for residential PV incentives.

4. Approval of the APS proposed set aside of $6 million in the budget for non-PV technologies.

5. Approval of the rapid reservation program as proposed.

6. Approval of the PPA for the Snowflake biomass plant output.

7. That the APS feed-in tariff pilot program not be approved at this time. However, Staff believes that the current workshop activities related to feed-in tariffs should be allowed to run their course before utilities implement feed-in tariffs, even on a pilot basis, given the significant financial commitment even a one year pilot program would entail.

8. That the incentive caps be set at 50 percent of total system cost for both residential and non-residential systems.

9. Approval of the Customized Incentives for the Home Builders program as proposed.

10. Approval of APS changes to the definitions of medium and large projects in the non-residential PBI program.

11. Approval of APS' request to eliminate the "10/20" PBI contract.

12. Approval of an increase of $5 million in residential up-front incentives; from $34 million to $39 million.

13. APS be ordered to file tariffs in compliance with the Decision in this case within 15 days of the effective date of that Decision The filed tariffs would be for:

    a) the proposed fees associated with the system interconnection process,
    b) the Schools and Government proposed rates, and
    c) the updated REST surcharge

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