BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

DIRECT TESTIMONY

OF

STEVEN M. FETTER

PRESIDENT

REGULATION UNFETTERED

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 15, 2006

I. INTRODUCTION AND BACKGROUND

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, NV 89014.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Arkansas Public Service Commission ("APSC" or the "Commission") on behalf of Entergy Arkansas, Inc. ("EAI" or the "Company").

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am President of Regulation UnFettered, a utility advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission ("MPSC").

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated with high honors from the University of Michigan with an A.B. in Communications in 1974. I graduated from the University of Michigan Law School with a J.D. in 1979.

Q. PLEASE BRIEFLY DESCRIBE YOUR ROLE AS PRESIDENT OF REGULATION UNFETTERED.

A. I formed a utility advisory firm to use my financial, regulatory, legislative, and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients include investor-owned and municipal electric, natural gas and water utilities, state public utility commissions and consumer advocates, non-utility energy suppliers, international financial services and consulting firms, and investors.

Q. WHAT WAS YOUR ROLE DURING YOUR EMPLOYMENT WITH FITCH?

A. I was Group Head and Managing Director of the Global Power Group within Fitch. In that role, I served as group manager of the combined 18-person New York and Chicago utility team and was also responsible for interpreting the impact of regulatory and legislative developments on utility credit ratings. In April 2002, I left Fitch to start Regulation UnFettered, a utility advisory firm.

Q. HOW LONG WERE YOU EMPLOYED BY FITCH?

A. I was employed by Fitch from October 1993 until April 2002. In addition, Fitch retained me as a consultant for a period of approximately six months shortly after I resigned.

Q. HOW DOES YOUR EXPERIENCE RELATE TO YOUR TESTIMONY IN THIS PROCEEDING?

A. My experience as a Commissioner on the MPSC and my subsequent professional experience analyzing the U.S. electric and natural gas sectors – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of a regulator's role in both setting rates and also determining appropriate terms and conditions of service for all regulated utilities. These are the factors that enter into the process of utility credit analysis and formulation of individual company credit ratings. It is a well-established fact that a utility's credit ratings have a significant impact as to whether that utility will be able to raise capital on a timely basis and upon favorable terms.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE REGULATORY AND LEGISLATIVE BODIES?

A. Since 1990, I have on numerous occasions testified before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, and various state legislative and regulatory bodies on the subjects of credit risk within the utility sector, electric and natural gas utility restructuring, utility securitization bonds, and nuclear energy. More specifically, I have previously testified on the issue of fuel and purchased power cost recovery mechanisms in several proceedings, including EAI's pending Energy Cost Recovery Rider ("Rider ECR") case, Docket Nos. 06-055-U and 05-116-U. Other cases in which I have filed testimony on that issue include on behalf of PSI Energy in Cause No. 42200 before the Indiana Utility Regulatory Commission and on behalf of Arizona Public Service Company ("APS") in Docket Nos. E-01345A-03-0437 and E-01345A-06-0009 before the Arizona Corporation Commission.

My full educational and professional background is attached in EAI Exhibit SMF-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports EAI's proposed Capacity Management Rider ("Rider CM") as an appropriate method to recover (1) incremental capacity costs associated with power purchase agreements ("PPAs") that include an explicit capacity component and (2) capacity additions between rate cases. My testimony will cover the following points:

- Why, from a regulatory and public policy perspective, a rider is an appropriate mechanism to recover the types of capacity costs associated with the Capacity Management Rider;
- How utility rating agencies view these types of transactions; and

- How these transactions impact the required return on common equity ("ROE") from capacity payments of PPAs.

In Direct Testimony, EAI witness Robert R. Cooper provides the resource planning justification and current market conditions that result in power purchase contracts that include an explicit capacity provision in the contract. Also in Direct Testimony, EAI witness Phillip B. Gillam proposes Rider CM and discusses its functional operation.

II. <u>DEVELOPMENT AND CURRENT STATUS OF CAPACITY COST RECOVERY MECHANISMS</u>

Q. CAN YOU PROVIDE SOME BACKGROUND ON THE ISSUE OF PURCHASED CAPACITY COST RECOVERY?

A. Yes. In my Initial Testimony in consolidated Docket Nos. 05-116-U and 06-055-U, I discussed why energy costs for public utilities are appropriately recovered through an exact recovery rider such as EAI's Energy Cost Recovery Rider ("Rider ECR"). Virtually every integrated electric utility has a need for both the procurement of fuel to fire its power plants and purchased power to deal with the peaks and valleys of electricity supply needed to serve its core regulated customers. Both utilities and regulators agree that overbuilding would place too large a financial burden on regulated customers, while a paucity of internal electricity supply would jeopardize the ongoing ability to provide reliable utility service to those same customers. Purchased power helps to fill the gap between a regulated utility's internal generation capacity and the fluctuating needs of its core customers. In addition, with the advent of competitive wholesale markets, a utility has the option of buying from the market when the market purchase price is less than the cost of self-generation.

As discussed in Mr. Cooper's testimony, today's purchased power market is moving toward contracts that contain both energy and capacity provisions. Independent Power Producers and power marketers are willing to provide products with a capacity call option or are willing to schedule power for the utilities' load needs when required. When such products are economically available to a utility's customers, a recovery mechanism for both the energy and capacity provisions of the power purchase agreement is reasonable. In essence, the power supplier is committing to provide power when needed, supplanting the need by the purchasing utility to construct additional capacity on its system. The power supplier is compensated for taking on the risk of contract performance through capacity payments, while the utility eliminates any overbuilding risk (and related construction risks) and gains flexibility that accrues to the ongoing benefit of its customers.

Q. WILL YOU DISCUSS WHY IT IS REASONABLE FOR A UTILITY TO RECOVER CAPACITY COSTS OTHER THAN IN BASE RATES?

A. As explained in Mr. Cooper's testimony, EAI has the opportunity to procure power through purchased power contracts that contain a capacity provision. Because both the quantity and price of these purchases can vary greatly from year to year, it is appropriate for the Commission to consider a recovery mechanism outside of the base rate framework. By removing guesswork with regard to potentially-needed capacity from the traditional base rate-setting process, the APSC is providing EAI with maximum flexibility to act in its customers' interests in contracting for secure power supply while feeling confident that it will receive fair financial recovery for its prudent actions. Such a balance is not easy to achieve through the use of base rates, which cannot be altered except through a lengthy and costly rate case process.

III. RATING AGENCY APPROACH TO THE CAPACITY ELEMENT OF PPAS

Q. HOW DO THE RATING AGENCIES VIEW PPAS WHEN ANALYZING THE CREDIT PROFILES OF ELECTRIC UTILITIES AND ASSIGNING RATINGS TO THEM?

A. All three of the major credit rating agencies view PPAs as debt-like in nature. Standard & Poor's ("S&P") explained its rationale in the leading report on the subject, "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements," published in May 2003 (attached as EAI Exhibit SMF-2):

> [S&P] views electric utility purchased-power agreements (PPA) as debt-like in nature and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." S&P applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as a debt equivalent.[1]

Thus, even when the energy component of a PPA is recovered in a timely manner through some form of rate adjustment clause or rider, the "capacity" component is analogous to a debt instrument in that it is fixed in nature, and subject to recovery risk through the ratemaking process. As S&P describes it, "When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense."[2]

The intent of Rider CM, in addition to providing fair recovery to EAI for prudently-taken actions with regard to needed electric capacity, is to lower the risk that rating agencies factor into their assignment of EAI's credit ratings.

Q. HOW HAVE CREDIT RATING FIRMS, SUCH AS S&P, CAPITALIZED SUCH OBLIGATIONS?

[1] S&P Research: "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements," May 8, 2003 at 1.
[2] *Id.*

A. S&P calculates a risk factor for a utility's long-term PPA obligation (in excess of three years) and then applies that factor to the net present value of the future stream of fixed (capacity) payments associated with such PPA.[3]

Q. WHAT DISCOUNT RATE IS TYPICALLY USED TO CALCULATE THE NET PRESENT VALUE OF FUTURE FIXED PPA PAYMENTS,

A. S&P typically uses a discount rate of 10 percent to calculate the net present value of future fixed PPA payments.[4]

Q. WHAT RISK FACTOR SHOULD BE APPLIED TO THE RESULTING NET PRESENT VALUE?

A. A risk factor can vary widely depending upon the perceived risk of timely recovery of such costs. The risk factor to be applied to the net present value of future fixed payments is generally in the 50 percent range, but in some cases, such as in jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of 30 percent may be used.

Q. HOW WOULD YOU IMPUTE THE PPA PAYMENTS AS DEBT INTO THE TRADITIONAL CAPITAL STRUCTURE OF THE PURCHASING UTILITY?

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[3] *Id.* at 2-3.
[4] *Id.* at 3.

A. The net present value of future fixed PPA payments, multiplied by the risk factor, is imputed as debt into the traditional capital structure of the purchasing utility – a capital structure comprising long-term debt, preferred stock and common equity. This debt imputation brings about a reduction in the common equity ratio and represents increased operational risk for the utility.

Q. WHAT IS THE RESULT OF THIS INCREASED RISK?

A. As Dr. Roger Morin states in his Direct Testimony in this proceeding, based upon his analysis of investor expectations, for every 1 percentage point reduction in the common equity ratio, the required investor return on common equity ("ROE") should increase by 11 basis points. Thus, as a utility increases its reliance on PPAs to fulfill a portion of its customers' load and energy requirements, its cost of common equity also will increase. Accordingly, in order for a utility to be encouraged to take the most appropriate power supply steps for its customers' benefit, it is absolutely critical that a utility's investors be compensated for the greater financial risk that increased reliance on PPAs brings to a utility's overall risk profile. Such compensation should take the form of an enhanced ROE commensurate with the recovery risk related to PPAs.

IV. EAI'S PROPOSED METHOD FOR RECOVERING THE REVENUE REQUIREMENTS ASSOCIATED WITH FIXED PPA PAYMENTS

Q. DOES THE CAPACITY MANAGEMENT RIDER ADDRESS THE INCREASED REVENUE REQUIREMENT ASSOCIATED WITH INCREASED FINANCIAL RISK?

A. Yes, I believe it does. EAI is proposing, with its Capacity Management Rider, a mechanism for recovering the increased revenue requirement associated with increased financial risk that would be attendant to increased levels of fixed PPA payments.

Q. HOW WOULD EAI CALCULATE THE INCREASED REVENUE REQUIREMENT?

A. For PPAs that are 3 years or longer in duration, EAI would calculate the net present value of the fixed payments, using a 10 percent discount factor, then apply a conservative 30 percent risk factor to arrive at the amount to be imputed into the capital structure as debt. This amount of debt is used to calculate an adjusted common equity ratio within EAI's traditional capital structure, which consists of long-term debt, preferred stock, and common equity.

The reduction in the common equity ratio within the traditional capital structure is then used to adjust the last approved return on common equity. As explained by Dr. Morin in his Direct Testimony, for each 1 percentage point reduction in the common equity ratio, the allowed return on common equity should increase by 11 basis points. The adjusted return on common equity is used to calculate a before-tax return on rate base using the Company's last approved modified balance sheet-based capital structure.

The resulting increase in the before-tax return on rate base is multiplied by the last approved rate base plus any acquired capacity rate base to arrive at the increase in revenue requirements associated with the increased risk related to the fixed PPA payments.

V. <u>CONCLUSION</u>

Q. DO YOU HAVE CONCLUDING THOUGHTS?

A. Yes I do. I believe that adoption of Rider CM is an appropriate and wholly reasonable approach to recognize and address the increased financial risk that the Company will face with new long-term PPAs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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EAI EXHIBIT SMF-1

RESUME OF STEVEN M. FETTER

STEVEN M. FETTER

1489 W. Warm Springs Rd. -- Ste. 110
Henderson, NV 89014
732-693-2349
RegUnF@comcast.net
www.RegUnF.com

Education University of Michigan Law School, J.D. 1979
Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. (Communications) 1974

April 2002 – Present
President – REGULATION UnFETTERED – Henderson, NV/Rumson, NJ

Founder of advisory firm providing regulatory, legislative, financial, legal and strategic planning advisory services for the energy, water and telecommunications sectors; federal and state testimony; credit rating advisory services; negotiation, arbitration and mediation services; and skills training in ethics, negotiation, and management efficiency.

- Service on Boards of Directors of: CH Energy Group (Chairman, Governance and Nominating Committee; Member, Audit; Previous Chairman, Audit and Compensation Committees), National Regulatory Research Institute (at Ohio State University), Keystone Energy Board, and Regulatory Information Technology Consortium; Member, Wall Street Utility Group and American Public Power Association; Participant, Keystone Center Dialogue on Financial Trading and Energy Markets.

October 1993 – April 2002
Group Head and Managing Director; Senior Director -- Global Power Group, Fitch IBCA Duff & Phelps -- New York/Chicago

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance.

- Led an effort to restructure the global power group that in three years time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

- Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

- Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002
Consultant -- NYNEX -- New York, Ameritech -- Chicago, Weatherwise USA -- Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993
Chairman; Commissioner -- Michigan Public Service Commission -- Lansing

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

- Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

- Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; Rejuvenated dormant twelve-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

- Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability; Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987
Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary -- U.S. Department of Labor -- Washington DC

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (<u>U.S. Labor Law and the Future of Labor-Management Cooperation</u>, w/S. Schlossberg, 1986).

January 1983 - August 1985
Senate Majority General Counsel; Chief Republican Counsel -- Michigan Senate -- Lansing

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the

Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 - January 1983
Assistant Legal Counsel -- Michigan Governor William Milliken -- Lansing

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982
Appellate Litigation Attorney -- National Labor Relations Board -- Washington DC

Other Significant Speeches and Publications

- Perspective: Don’t Fence Me Out (Public Utilities Fortnightly, October 2004)
- Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998)(unpublished)
- Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)
- The Feds Can Lead…By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)
- Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)
- Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)
- Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

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EAI EXHIBIT SMF-2

STANDARD & POOR'S REPORT

'BUY VERSUS BUILD': DEBT ASPECTS OF

PURCHASED-POWER AGREEMENTS

Research:

"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Publication date: 08-May-2003

Credit Analyst: Jeffrey Wolinsky, CFA, New York (1) 212-438-2117; Dimitri Nikas, New York (1) 212-438-7807; Anthony Flintoff, London (44) 20-7826-3874; Laurie Conheady, Melbourne (61) 3-9631-2036

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery--and thus release from the payment obligation--is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build--i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%--10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (11 plus 48). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Table 1 ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		**Adjusted capital structure**	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	-	-	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2 ABC Utility Co. Adjustment to Pretax Interest Coverage

		Original pretax interest coverage (x)		**Adjusted pretax interest coverage (x)**	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means.

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record this 15th day of August 2006.

/S/

Steven K. Strickland