BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Progress Energy Florida, Inc.

Docket No. 050078-EI

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DIRECT TESTIMONY OF

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DIRECT TESTIMONY OF

<u>THOMAS R. SULLIVAN</u>

I. <u>Introduction and Summary</u>.

Q. Please state your name and business address.

A. My name is Thomas R. Sullivan and my business address is 410 S. Wilmington Street, PEB 19A3, Raleigh, North Carolina, 27601.

Q. What is your position with Progress Energy Florida?

A. I hold the position of Treasurer at Progress Energy Florida, Inc. ("PEF" or the "Company"). I am also Vice President – Treasurer and Chief Risk Officer of Progress Energy Service Company.

Q. Would you please briefly outline your qualifications and professional experience?

A. I came to Carolina Power & Light Company as Manager – Financial Operations in November 1997 and was later promoted to Vice President and Treasurer of Progress Energy. I am responsible for all capital raising activities for Progress Energy and its subsidiaries. As Treasurer and Chief Risk Officer, I have responsibility for Financial Operations, Corporate Insurance, Financial Analysis and Enterprise Risk Management. Prior to joining Carolina Power & Light Company, my seventeen years of business experience included serving as Director - Treasury Capital Markets at Visa International Service Association, Assistant Treasurer of LB Credit Corporation, various financial positions within Signal Capital Corporation, and fixed income analyst at Liberty Mutual Insurance Company.

I have a bachelor's degree from St. Lawrence University and a master's degree in business administration from Northeastern University.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the capital structure of PEF and the impact long-term purchase power contracts (PPAs) have on our financial policy. The treatment of these contracts by the rating agencies affects financial ratios, in particular leverage ratios, used to determine a company's credit rating. As Treasurer, it is my responsibility to maintain PEF's capital structure in a manner which supports our target credit rating, therefore I must take into consideration the adjustments a rating agency may make when developing its financial ratios to assess its credit rating.

Q. Do you have any exhibits to your testimony?

A. Yes, I have the following exhibits to my direct testimony:

- Exhibit No. ______ (TRS-1), *Credit Implications of Power Supply Risk*, Moody's Special Comment, July 2000.
- Exhibit No. ___ (TRS-2), *Standard & Poor's Research: "Buy versus Build": Debt Aspects of Purchased-Power Agreements*, May 8, 2003.
- Exhibit No. (TRS-3), *Fitch presentation to Progress Energy*, October 2003.

These exhibits are true and accurate.

Q. What is your target credit rating for PEF?

A. The long-term target credit rating for PEF is single A for its senior secured and unsecured debt.

Q. How many rating agencies perform credit analyses on Progress Energy Florida?

A. Three rating agencies, Standard & Poor's Rating Service, Moody's Investor Service and Fitch Ratings, provide credit ratings for PEF.

Q. What is the current credit rating for PEF?

A. The following table summarizes the credit ratings for PEF for each of the three major rating agencies which currently rate PEF's debt.

	S&P	Moody's	Fitch
Senior Unsecured	BBB	A3	BBB+
Senior Secured	BBB	A2	A-

Q. Why is it important for PEF to obtain an "A" rating from all three rating agencies?

A. Investors distinguish between companies with split ratings versus companies who have the same rating across all rating agencies. The lower rating in a split-rated company will result in a higher cost of debt for that company.

Q. Why do you target "single A" as PEF's long-term debt rating?

A. A strong credit rating assures PEF access to low-cost debt during both good and difficult capital market conditions. PEF, like other electric utilities, has the obligation to serve its customers. This obligation requires access to the capital markets under all market conditions. In other words, the flexibility surrounding the timing of a security issuance for a regulated electric utility can be limited. Unlike nonregulated companies, PEF cannot easily change the timing of its capital spending, and therefore the timing of security issuances. These commitments are driven in large part by its obligation to serve, a 20% reserve margin requirement, and ever growing environmental compliance requirements. This requires that PEF be able to issue low-cost debt securities during all market conditions.

Q. How do these rating agencies treat long-term power supply contracts when evaluating a company's credit profile?

A. While each one's specific method may vary, they all base their analysis on the premise that long-term fixed payments associated with these contracts are essentially debt-like in nature, much like a long-term lease on property, plant, and equipment. The following excerpts from the three rating agencies' public statements illustrate this consistent view among the agencies:

MOODY'S

"Moody's will continue to view these off-balance sheet obligations as debt – in particular those purchased power obligations that are above market." Credit Implications of Power Supply Risk, Moody's Special Comment, July 2000. Exhibit No. ___ (TRS-1)

STANDARD & POOR'S

Standard and Poor's Ratings Service (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 Research: "Buy versus Build": Debt Aspects of Purchased-Power Agreements.* May 8, 2003. Exhibit No. ___ (TRS-2)

FITCH

For purchased power agreements, operating leases, tolling arrangement, and synthetic leases, Fitch policy varies from GAAP accounting rules in order to capture operating leverage. Fitch presentation to Progress Energy, October 2003. Exhibit No. ___ (TRS-3). S&P, who actually makes a numerical adjustment to PEF's ratios, recently modified its methodology. (See Exhibit No. ___ (TRS-2)). Under S&P's approach, future capacity payments are discounted using a 10% discount rate. The net present value of those payments is multiplied by a risk factor, the result of which is the amount of imputed debt included in certain financial ratios, including its adjusted leverage ratio. For PEF, S&P uses a risk factor of 30%. S&P will also impute an amount for interest expense associated with the imputed debt by multiplying the imputed debt amount by 10%. This amount is included in interest coverage ratios.

Q. What is the impact on a company's credit profile when rating agencies treat long-term power supply contracts as debt-like?

A. The main effect is that a company is considered to have more leverage than if you calculated its leverage ratio based only on the debt recorded on its balance sheet.

Q. Does PEF have long-term power supply contracts?

A. Yes, PEF has a substantial amount of purchase power commitments relative to its total generation mix. As of December 31, 2004, PEF had 489 MWs of purchased power with other utilities and 821 MWs with certain cogenerators (QFs).

Q. What is the basis for S&P's risk factor adjustment?

A. As stated in S&P's article "*Buy versus Build*" the overriding factor influencing the risk factor is the likelihood of payment by the buyer. It notes that the probability of nondelivery by independent generators is quite low, thus the probability of a buyer having to pay for purchased power, is quite high. Given the high likelihood of payment by the buyer, these long-term fixed obligations are assigned a higher risk factor for purposes of imputing debt. S&P states that PPAs are viewed as a fixed commitment and when a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk.

S&P's generic guideline for utilities with PPAs of over three years is to use a 50% risk factor. According to S&P, the 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. S&P does view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant." Exhibit No. ___ (TRS-2).

Q. Do you agree with S&P's use of a 30% risk factor for calculating imputed debt for PPAs?

A. I agree with the concepts underlying S&P's methodology. By entering into long-term PPAs, you are entering into a long-term fixed commitment, which is debt-like in nature.

However, I don't think S&P has given the appropriate recognition to the unique circumstances surrounding PEF's regulatory treatment of these contracts, which is very important in determining the appropriate risk factor. On February 24, 2005, we discussed with S&P our views regarding the use of a 30% risk factor. We stated, among other things, that the strength of the regulatory recovery clauses in place to recover capacity payments associated with these contracts did not support a 30% risk factor. To my knowledge, S&P has not changed their position on this issue and until they do, we must consider their calculation for imputed debt when assessing PEF's capital structure.

Q. How much debt and interest expense does S&P impute when assessing the impact of PPAs on PEF's credit ratios?

A. As of December 31, 2004, the present value (using a 10% discount rate) of PEF's future capacity payments for its QF and utility PPAs was approximately $2.7 billion. S&P then computes the amount of imputed debt by applying a 30% risk factor for PEF, which results in approximately $806 million of imputed debt. S&P would impute $80.6 million of additional interest expense based on an assumed interest rate of 10%.

Q. Does this amount change each year?

A. Yes, assuming we do not enter into any other PPAs, the amount of imputed debt is projected to decline over time as the termination date of the contract approaches.

Q. What is S&P's impact on PEF's capital structure when imputing debt associated with long-term PPAs?

A. The following table shows PEF's projected capital structure for year- end 2006. Off-balance sheet (OBS) obligations include $757 million related to PPAs and $20 million for leases, a standard adjustment when calculating off-balance sheet liabilities.:

	2006 (with OBS)		2006 (without OBS)	
Short-term Debt	40,517	0.69%	40,517	0.80%
Long-term Debt	2,213,254	37.77%	2,213,254	43.54%
OBS Obligations	777,010	13.26%	-	-
Preferred Stock	33,497	0.57%	33,497	0.66%
Common Equity	2,795,551	47.71%	2,795,551	55.00%
Total Capital	5,859,828	100.00%	5,082,818	100.00%

Q. How does S&P's treatment of these contracts affect your financial policy?

A. Our financial policy must take S&P's adjustments into consideration if we are to achieve our target debt rating for PEF. This means that when developing target capital structure ratios, we must consider the impact of off-balance sheet items, in particular long-term power supply agreements due to their material impact on PEF's leverage.

If we were to ignore long-term purchase power contracts, as well as other off-balance sheet obligations, we would be setting target leverage ratios which would be inconsistent with S&P's view of our leverage.

Q. What leverage ratio is necessary for PEF to achieve a "single A" rating by S&P?

A. S&P considers PEF to have a business risk profile of "5". Their published guidelines state that adjusted leverage ratios for utilities with a business risk profile of "5" must range between 42% and 50%. While there are many factors taken into consideration by

S&P in determining the final credit rating, the leverage ratio is an important ratio. The mid-point of this range is 46% and would be the target leverage ratio for a company seeking to achieve a "single A" credit rating.

As shown above, the effect of off-balance sheet obligations changes PEF's projected 2006 leverage ratio from 45% (including preferred stock) to 52.29%, well above the mid-point of 46%.

Q. Has the Commission ever recognized the affect of off-balance sheet obligations like PPAs on a utility's capital structure?

A. Yes. Rule 25-22.081(7) requires utilities to include a discussion of the potential for increases or decreases in its cost of capital should a purchase power agreement with a non-utility generator be made.

In addition, the FPSC has recognized the impact of long-term PPAs when comparing the cost of building generation with the cost of executing a long-term power supply contract. [Order No. PSC-04-1168-FOF-EI, dated November 23, 2004.]

Lastly, FPSC has recognized the effects of long-term PPAs in Florida Power & Light's (FPL's) current revenue sharing agreement. Order No. PSC-02-0501-AS-EI, April 11, 2002, incorporates by reference the following provision from the Stipulation and Settlement approved by the FPSC in 1999, Order No. PSC-99-0519-AS-EI, March 17, 1999.

As stated in the Order:

> "FPL's adjusted equity ratio equals common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations. The amount used for off-balance sheet obligations will be calculated per the Standard & Poor's methodology as used in its August 1998 credit report."

Q. How should PEF's rates be adjusted for the effect of imputed debt associated with long-term PPAs?

A. PEF's weighted average cost of capital (WACC) should reflect the effect of imputed debt associated with long-term PPAs by recognizing on a proforma basis the amount of equity necessary to offset the effect of imputed debt. This approach is conceptually consistent with the recognition of PPAs in FP&L's capital structure calculation.

PEF's projected 2006 capital structure reflects a 55% common equity ratio, before taking long-term purchase power contracts into account. PEF would need $757 million of additional equity in its capital structure to maintain a 55% equity ratio <u>after</u> recognizing imputed debt associated with these contacts. PEF's WACC should be adjusted to properly reflect the additional equity necessary to offset the additional imputed debt. This adjustment is conceptually consistent with FPL's current revenue sharing agreement referred to above. The only difference is while PEF makes a proforma adjustment to the amount of equity in its capital structure for purposes of calculating its WACC, FPL makes a proforma adjustment to the amount of debt. However, the impact on WACC is the same.

Q. What is the benefit to the Company and the customer in recognizing the imputed debt associated with long-term PPAs?

A. Recognizing the imputed debt associated with long-term PPAs in this base rate proceeding would be a positive development for PEF's credit profile. I would expect S&P to view the Commission's recognition of these contracts as imputed debt and adjusting its WACC as enhancing to PEF's credit quality. Improving PEF's credit quality, and possibly its long-term credit rating, will reduce PEF's cost of borrowing as bond investors would consider PEF to have lower credit risk.

Q. What is the risk to the Company and customers if the Commission does not recognize any imputed debt associated with long-term PPAs?

A. The risk to the Company and customers is that PEF's credit quality will continue to suffer due to the lack of recognition of these contracts. As stated earlier, S&P considers the addition of long-term PPAs as increasing financial risk and makes adjustments to PEF's credit ratios to reflect this additional risk. The result of this is higher debt costs to PEF, weaker access to the capital markets, and an overall weaker credit profile, which puts PEF at greater risk of a downgrade. S&P currently has a negative outlook for PEF. An unfavorable outcome of PEF's base rate proceeding, including the treatment of long-term PPAs, would have a negative impact on PEF's credit profile and could result in a downgrade. This would further increase PEF's borrowing costs and further weaken its access to the capital markets.

Q. Has the FPSC ever made proforma adjustments to a utility's capital structure for ratemaking purposes?

A. Yes, PEF's existing revenue sharing agreement recognizes an adjustment for certain costs incurred during PEF's 1997 Crystal River nuclear outage. In this agreement, PEF's common equity is increased $109 million for purposes of calculating its return on equity. In addition, FPL's current revenue sharing agreement provides for a specific calculation of capital structure ratios which takes into account S&P's calculation of imputed debt associated with long-term power supply contracts.

Q. Does this conclude your testimony?

A. Yes, it does.

Moody's Investors Service
Global Credit Research

July 2000

Special Comment

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Credit Implications of Power Supply Risk | Special Comment

Credit Implications of Power Supply Risk

Summary Opinion

Of all companies exposed to the risks of open competition in the power industry, power energy trading firms, aggregators, and energy service companies are most exposed to supply risk and the most vulnerable to volatile market prices during periods of high energy demand or capacity shortages. While transmission and distribution (T&D) companies remain regulated, they are not free of risk – particularly those companies still bound by capped rates that have sold their generating assets. For that matter, even certain vertically integrated utilities, those that are capacity short and operate without a purchased power adjustment clause, remain exposed to supply risk.

As the market shifts, Moody's analysis becomes increasingly focused on how well companies hedge the new supply risk and whether they do so in a manner that will enable them to maintain their financial integrity and their bond ratings. Part of this analysis will focus on the adequacy of the company's liquidity to withstand large shifts in electric prices. Moody's will make this determination on a case-by-case basis for regulated transmission and distribution utilities, supply companies, vertically integrated power companies and for all participants exposed to the price volatility associated with electricity supply.

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The Impact Of Risk Migration

In a competitive environment, supply risk can be transferred and hedged, but it cannot be eliminated. Some party in the power chain must manage the risk. Unfortunately for both regulated and unregulated energy providers, managing this risk is no easy task.

Unregulated supply companies that have not secured all of their generating resources are exposed to increased costs when electric prices rise. Conversely, these same entities can be exposed to another type of supply risk when they secure additional resources and prices or demand decline.

Regulated vertically integrated utilities operating without regulatory recovery of potentially high electricity costs from spot-market purchases are equally vulnerable, particularly during periods of peak energy demand and/or supply shortages.

Moreover, transitioning utilities, particularly those that have sold their generation and are operating under a rate freeze, remain exposed to the risk, in many cases, by acting as a Provider of Last Resort (PLR), especially in power constrained markets. State commissions are still wrestling with the best approach toward dealing with PLR risk and in some cases, may transfer the risk to the customer or provide the regulatory mechanism for recovery.

Moody's ultimately believes that companies exposed to supply risk must demonstrate the ability to appropriately hedge this risk in order to preserve its financial integrity and maintain its bond rating.

Prospectively, Moody's ratings will adjust to reflect this changing market dynamic as the industry continues to make its transition and vertically integrated utilities "disintegrate".

HOW MOODY'S VIEWS THE RISK IN CONTRACTUAL SUPPLY OBLIGATIONS

When analyzing companies that must secure supply for their customers, Moody's will review the company's risk policy and supply strategy as it relates to long-term purchase power agreements (PPAs), short-term to medium-term supply agreements and ownership of generating assets. As the separation of generation assets continues, Moody's will consider market-based arrangements as being akin to any other contracted operating expense. Higher cost or above market contracts will continue to be viewed in a more negative light.

- **Vertically Integrated Companies with Long-Term PPAs:**

  Traditionally, long-term off-balance sheet PPAs have been viewed as debt as the PPA obligation did not enhance rate base or returns to shareholders thereby compromising a degree of financial flexibility. Moreover, many of these contracts contained prices that proved to be above – market. Moody's will continue to view these off-balance sheet obligations as debt — in particular those purchased power obligations that are above market.

- **Transitioning Companies with Long-Term PPAs:**

  For companies that have divested all or substantially all of their generating assets but still have existing long-term PPAs in place and are focusing on T&D business, the manner in which cost recovery is being handled will help to determine the treatment of these obligations.

  To the extent that restructuring legislation provides pass-through recovery of the costs, Moody's will view these as being neutral to credit quality — particularly if the amounts of these above-market PPA obligations decline over time.

- **Provider of Last Resort Obligation:**

  Companies transitioning from a vertically integrated utility to a regulated T&D company remain vulnerable to a specific type of supply risk when they function (either by law or by choice) as Providers of Last Resort (PLRs). PLRs are required to serve as the default provider for all customers that do not make a choice of supplier. In many cases, PLR service defaults to the regulated T&D company, many of which are operating under some type of rate cap, thereby exposing these PLRs to supply risk.

  Adding to the uncertainty is the fact that a number of these transitioning T&D utilities have sold virtually all of their generating resources as a means of recovering stranded costs, with the view that customer choice would transfer the majority of this risk onto another provider. Although customers have switched providers, the number of customers that have opted for choice is below original expectations, and in some cases, customers that have switched have returned to the utility.

The degree of supply risk at any given time will depend on the regulatory policy that applies in terms of allocating costs, volatility risks, and the risks associated with commodity competition to the regulated company. Companies who retain PLR customers are likely to seek regulatory recovery of the costs associated with supplying this service. Others may be willing to assume supply risk without recourse to customers, particularly if the tariff is large enough to provide a meaningful cushion against the potential volatility in the commodity. Moody's views this strategy as being more risky.

Only "pure" T&Ds are not exposed to some manner of supply risk. "Pure" T&Ds would be those T&D companies that do not own or contract for supply, as well as those that have completely sold or transferred the PLR function with no regulatory expectation of any further involvement by the regulated utility and no cost exposure to the regulated utility.

WHO ASSUMES THE COMMODITY RISK ASSOCIATED WITH ELECTRICITY SUPPLY?

It is important to recognize that the commodity risk associated with electric supply has always existed in the industry. That risk has largely been borne, however, by ratepayers.

BEFORE DEREGULATION, IT WAS THE CUSTOMER...

When dealing with a vertically integrated utility, a fully bundled rate (determined by rate of return and return on rate base measures) masked the commodity risk contained within the electricity rate. In addition, utilities were typically able to recover (from ratepayers) changes in their electric prices incurred as a result of fuel cost adjustments or purchased power adjustments by implementing a purchased power or fuel adjustment clause or, at worst, a fuel rate case.

Although ratepayers have unknowingly assumed the commodity risk, the risk was passed on to them under the watchful eye of a regulator. Recovery typically was phased in over a 12-month timeframe, at a *minimum*, which served to levelize the cash impact on ratepayers, albeit creating a cash flow timing lag for the utility to be made whole.

Nearly Half of the U.S. Passes Restructuring Legislation

As of July 2000, 25 states had passed restructuring legislation granting all retail customers choice of generation supplier. This means that half of the United States has changed the way its electric power industry is operated.

In most of the states that have restructured, the motivators were often customers tired of paying high prices for electricity – although a few states with relatively low power supply costs and reasonable service reliability, including Oregon, Oklahoma, and Montana, have undertaken such legislation. Some states, like New York, have not yet succeeded in passing restructuring legislation, but have nevertheless introduced retail customer choice through the regulatory process. Most states are phasing in retail choice for all customers by 2002 at the latest, with the exception of Virginia, which will be phased in between 2002 and 2004.

Regulatory Support Helps Industry Transition to Competition

Generally speaking, states have permitted utilities to recover significant portions of their stranded investments, and have allowed for a multi-year phase-in of retail customer choice for generation supply. The phase-in or transition period and the implementation of a "competitive transition charge" are permitting utilities to recover sizable portions of stranded costs stemming mostly from large generation facilities and high-cost purchased power contracts.

For many utilities on the east and west coasts, large portions of stranded costs were attributable to "above-market" power purchase agreements, mandated under the Public Utility Regulatory Policy Act of 1978.

...UNDER DEREGULATION, IT'S THE CUSTOMER, THE SUPPLIER OR THE PLR PROVIDER

In a competitive environment, commodity risk still exists and is, in fact, more volatile than in other commodity industries because electricity cannot be stored. The ultimate price is driven by supply and demand requirements, which can deviate quickly under unmanageable events such as severe weather or a generating station's tripping off the electric grid.

Although commodity risk is acute for all parties it will, through market contracts or through regulatory action, be transferred from one party to another. Potential bearers of this risk include the customer, the unregulated supply company or the PLR provider — which could either be the utility or another party that purchases that business from the utility.

The Logic of Keeping Commodity Risk with the Customer

Many of the early architects of electric restructuring legislation have been operating with the premise that the customer should bear all the commodity risk.

The logic holds that, in a competitive environment, customers have choices. Competition should, theoretically, force electric prices down over time. Also, customers have always assumed this risk, even though the state commission monitored the prudency of the resulting price changes and recovery was made in levelized payments.

Customers of some utilities may, over time, be more willing to bear this commodity risk — particularly those living and working in moderate climates with lower year-round usage and moderates peaks. Others, particularly customers of utilities located in the Southwest or Texas, may have difficulty accepting this risk, particularly during periods of high usage and high price volatility. (***See the California Case Study for further discussion of customer's reaction to bearing this risk.***)

ENERGY SERVICE COMPANIES LIKELY TO ABSORB PRICE VOLATILITY, PUTTING MARGINS AT RISK

In most cases, we believe that energy service companies engaged in power supply aggregation will assume much of the price volatility risk through programs offered to customers where rates are fixed or indexed but set below the standard offer rate. Margins will be negatively affected, however, to the extent that the energy service company's cost to supply that load increases.

These at-risk entities, which can include affiliates of utilities, will likely hedge their relative contract positions with physical assets or bilateral contracts. Capacity-short markets, like those of the Midwest or portions of the West, have the potential to affect these entities negatively, particularly those that are more reliant on the market place for supply. An affiliation with a strong energy trading and marketing company is an absolute necessity for this business.

Table 1

Examples of Companies that Have Sold or Contracted Out their Supply Obligation

Bangor Hydro
Cambridge Electric
Central Maine Power
Commonwealth Electric
Connecticut Light & Power
Duquesne Light Company
Montana Power
New England Electric System
United Illuminating
Western Massachusetts Electric

PLR PROVIDERS REMAIN EQUALLY EXPOSED

PLR service poses risks to potential providers. For most distribution utilities, PLR customers are likely to be sizable in number and predominantly residential and small commercial. In most states, however, regulators remain unclear about the best way to handle PLR service. Adding to the uncertainty is the fact that a number of utilities have sold virtually all of their generating resources, making it financially risky for them to provide PLR service. In California, Pennsylvania, Illinois, and most of the New England states, for instance, a number of the utilities have sold large portions of their generating capacity.

In general, utilities have little incentive to accept the financial risk PLR service creates without being compensated by regulators with some form of pass-through. Each state will determine its own plan, and Moody's believes that elements of a purchased power adjustment clause will be retained for PLR service.

The Varied Supply Risks Of Different Business

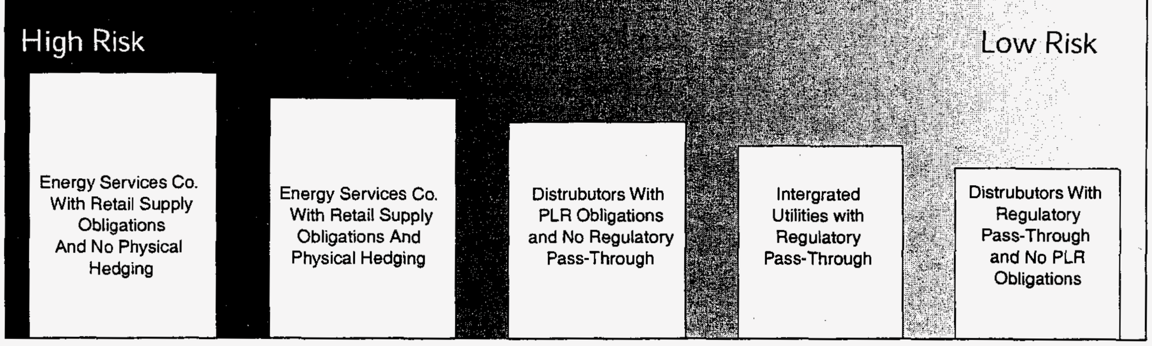
The level of supply risk varies given the type of business a utility elects to be in.

On the risk continuum, a regulated transmission and distribution company without generation assets and without a PLR obligation would be exposed to the lowest level of supply or commodity risk.

The regulated distribution company with the PLR obligation will have slightly higher risk, because it will remain obligated to purchase power from other suppliers to serve those customers on its delivery system who do not choose an alternate provider.

At the far end of the continuum (*Table 2*) is the unregulated supply company, whose energy costs are dictated by the market and who is exposed to the highest level of supply risk.

Table 2
Supply Risk Continuum



Following are examples of different business segments with different levels of supply risk. The order ranges from the business sector with the highest supply risk to the business segment with the lowest level of supply risk:

- **Energy Services Companies with retail supply obligations** clearly possess the highest form of supply risk. This business approach challenges these providers to implement strong supply risk hedging strategies, including, in some cases, securing physical plant.

  Moody's anticipates that this sector could be the source of unanticipated negative news as competition rolls out throughout the country. In all likelihood, the most competent supplier will be one that has access to all types of generating capability, (i.e., base load plants, mid-merit facilities, and peakers), has regional diversity, a strong fuel mix, and employs superior risk management strategies through its marketing and trading businesses.

- **Regulated transmission and distribution companies** remain vulnerable to energy price risk associated with power supply and purchased power if they have a PLR obligation in a deregulated environment.

Texas Approach Can Insulate T&D Utility from Supply Risk

The Texas electric restructuring law, signed June 1999, requires a legal separation of the retail electric provider (REP) from the T&D company. The REP is defined as a person or entity that sells electric energy to retail customers in Texas. The new REP will perform the aggregation and supply role, with the T&D entity providing the transportation and delivery function. Moody's notes that the legal separation contemplated in Texas should insulate the T&D company from supply risk. The Texas law permits all retail electric customers a choice of generation supplier beginning January 1, 2002.

The degree of risk will depend on regulatory treatment of these costs. Entities with regulatory mandated price caps or no regulatory pass-through mechanism could face higher risks. Entities without price caps and a regulatory pass-through mechanism should face lower risks.

The business and financial risks of these companies are relatively low given that their regulated revenues are more stable and predictable. For such PLR providers to mitigate supply risk, however, either the customer must assume it or the state regulatory agencies must permit recovery of supply costs associated with any necessary power purchases. Without regulatory permission to recover purchased power costs, the financial flexibility of these utilities could weaken.

Massachusetts: Default Service exposes T&D's to Supply Risk

In Massachusetts, a unique supply risk is unfolding. The Massachusetts utilities, all of whom operate as T&D companies, are required to provide "default service" to those customers that first switch to competitive providers but elect to return to the utility system.

Under Massachusetts law, these customers must be served by the local T&D company at the default service rate. However, the rate for "default service" is substantially below the electric wholesale price that a T&D must pay to meet this load.

In Massachusetts, "standard offer customers" also exist and they represent those customers that have elected not to use a competitive provider. The standard offer rate tracks closley to the default service rate.

As depicted in Table 1, USGen New England secured the standard offer service from New England Electric System (NEES) when it purchased NEES's generating assets. Massachusetts Electric, then a NEES subsidiary and now a T&D utility owned by National Grid (USA), is the supplier for default service. Massachusetts Electric has publicly stated that it could lose up to $41 million on default service over the summer months, since the wholesale price to serve the load is much higher than the default service rate.

At the same time, generators including USGen NewEngland, which own the generating assets that had served customers of Massachusetts Electric, stand to benefit from default service.

To address this concern, the Massachusetts regulators have modified the terms and conditions for default service by increasing the tariff rate for default service to a rate that is aligned with the wholesale market. In this way, customers that have selected a new provider will have a lower incentive to switch to default service. The modification is effective January 1, 2001.

HEDGING PRICE VOLATILITY AND SUPPLY RISKS

The effective use of financial hedging instruments such as derivatives to stabilize pricing volatility is necessary for energy service companies to mitigate the financial risk associated with providing power supply.

The risk associated with marketing and trading around generating assets is more manageable than the trading of derivatives based on the commodity prices. When a company uses financial derivatives, it is only to lock in prices. Certain financial derivatives do not mitigate supply and deliverability risk.

Supply risk can be mitigated only through access to a diverse pool of generation assets — either through physical assets or through contracts. Moreover, deliverability risk becomes minimal in instances where the power supply contracts are backed by reserves or generating plant.

The supply business can provide a natural hedge for generators. In Chile, which has been deregulated for some time, generators act as the suppliers for large customers as they sign bilateral contracts with distributors and large-end users. The generators' ability to sign these contracts provides them with a customer for their output thereby mitigating one element of supply risk. Similarly, in other commodities, such as petrochemicals or oil, the supply side of the business can provide a natural hedge for the producer.

Still, there are risks to hedging with physical assets or with contracts. Power providers (supply companies, marketers, or aggregators), who are long on capacity by signing additional purchased power contracts or by buying or building electric generation in anticipation of strong energy consumption, may not be allowed to recoup these costs from the market if there is a prolonged period of cool summers, a reduction in demand, or an overbuilt supply market with too much capacity. This would result in the power

Will the Current Vintage of Tolling Agreements Become the Next Round of High-Priced PPA?

As competitive markets have developed, the market has created a tool that provides trading and marketing companies with dedicated supply to help support their marketing business. The cornerstone of this structure is the tolling agreement, which is typically a 20-year contract between a marketing company or a supply company and a generator.

Under a typical tolling agreement, the marketer or the supply company pays a tolling fee or capacity payment to the generating plant for the right to deliver gas to the plant for electric generation. The capacity payment is typically a fixed contracted amount and is paid based on predetermined capacity factors for the plant. Presumably, the generator will be asked to produce electricity when the marketing company believes it is economical to utilize the electric output from the plant.

If regional energy prices remain below a plant's marginal cost to produce electricity, it is plausible that the marketing company would not elect to utilize the plant's output. In this case, the toller would still be required to make capacity payments to the plant, assuming that the plant was available for output. More importantly, if this scenario occurred over an extended period of time, regional electric energy and capacity prices would likely be depressed for a sustained period due to severe regional overcapacity or materially lower than expected output. Consequently, a scenario could be realized wherein the capacity payments under a tolling arrangement *end up becoming the next round of high priced* PPAs.

Although this scenario is indeed plausible, particularly given the length of the tolling agreements and the still-uncertain outlook for future energy prices, Moody's believes that the market nature of these contracts serves to mitigate this risk. Unlike the PPAs of the eighties and nineties, which, in many cases, had terms that were driven by federal and state regulators, the current tolling arrangements are market driven and are entered into by marketing companies that are in the business of managing this type of risk.

Moody's recognizes that market-driven agreements do not always mean rational markets or rational counterparties. There are countless examples of irrational markets and irrational market decisions scattered throughout a number of industries. However, Moody's does believe that the current vintage of tolling agreements have contract terms for the toller that are currently economical for them, and are likely to remain competitive in an open market.

providers having to absorb the higher costs associated with operating the plant or with having an above-market purchased power contract.

(Please refer to the following Special Comments: "Energy Trading: Essential to Energy Markets, But Risky", April 1999, and "Counterparty Risk Management After June 1998: Improvements in the Works", May 1999.)

ADEQUATE LIQUIDITY REMAINS AN IMPORTANT MITIGANT TO SUPPLY RISK

Moody's believes that access to adequate liquidity remains an important element to mitigating supply risk. Suppliers of electricity, particularly those that must purchase electricity in the spot market, can be exposed to higher cash costs and unpredictable cash needs during periods of high prices and high volatility. Additionally, suppliers of electricity are likely to have higher seasonal cash needs due to the higher usage that typically occurs in the summer months.

Companies, including vertically integrated utilities, transitioning utilities, nonregulated supply companies, and PLR providers are all exposed to this burgeoning risk. This liquidity need is a relatively new issue for financial officers to think about. Prior to deregulation, vertically integrated utilities provided the bulk of their own power needs and purchased any additional needs in a bilateral contract market. Although wholesale market prices fluctuated, the relative volatility pales in comparison to the price volatility experienced in today's power markets. Short-term liquidity was more manageable and purchased power adjustment clauses served to isolate the cash flow risk. Additionally, few companies, if any, were completely reliant on other providers for their supply, a condition that exists today for supply companies that have limited access to their own generating assets.

Moody's will examine the liquidity needs of companies assuming supply risk under a variety of downside scenarios to determine the company's access to liquidity should power markets move against a particular company for an extended period of time.

SOME CASE STUDIES INDICATE THAT SUPPLY RISK REMAINS AN ISSUE FOR STATE REGULATORS

The California Case Study

In California, retail customer choice began in January 1998. All the California investor-owned utilities are now largely state-regulated distribution companies. They have divested their in-state fossil-fueled generating assets and have plans to divest of most of their remaining generating assets.

These California utilities are permitted to recover all of their stranded investments through March 2002 and the high costs associated with their purchased power contracts through the life of each contract. Each utility maintains a PLR obligation.

During the transition period, the utilities are required to sell the generation from their purchased power portfolios to the California Power Exchange (PX). When the price received from the PX is lower than the price that the utilities must pay under their purchased power contracts, the utilities have the legal right to collect that difference from ratepayers over the term of the contracts. All three utilities must purchase power from the PX to meet the complete needs of the customers who have not chosen commodity service from a retailer.

During the transition period, the utilities cannot charge more than a frozen rate level, even if energy prices in the PX, when combined with the other components of the tariff are above the level of the frozen rates.

CURRENT CALIFORNIA PRICES SHOWS THE VOLATILITY IN ELECTRIC PRICES

One unrelated but important observation from this current development in San Diego is the tremendous volatility that exists in electric prices and the impact that other markets have on the price of electricity. SDG&E's service territory has among the most moderate climates in the country and typically does not experience any material peaks. The 2000 summer, although warmer than most summers, has been fairly typically of past summers. However, the adjoining Southwest market that includes summer peaking markets like Las Vegas and Phoenix, impact regional demand and when coupled with reduced capacity in California and in the West, cause prices in the California PX to increase.

Two of the three utilities remain on the rate freeze as of July 2000 (only San Diego Gas and Electric Company (SDG&E) has concluded the rate freeze). The two utilities, Pacific Gas and Electric Company and Southern California Edison Company are taking supply risk during the transition period. After the transition period, however, it is contemplated that customers will bear the energy price risk, serving to shift the commodity price risk away from the utility.

In mid-1999, SDG&E fully collected its stranded costs and terminated its rate freeze with its customers. Because of this, all customers enjoyed further declines in rates beginning in July 1999 reflecting the collection of all stranded costs. However, because SDG&E was two and a half years ahead of schedule in collecting stranded costs, the California Public Utilities Commission (CPUC) was not prepared for this timing and still had not determined how PLR service should be implemented after the transition period. Not surprisingly, the CPUC reverted to traditional regulation for the summer of 1999 by authorizing that PLR customers be guaranteed that their price for generation would not be in excess of the average PX rate plus 12.5%. However, if energy costs for customers exceed this cap, SDG&E had the authority to create a regulatory balancing account that would be recoverable from these customers over the next nine-month period.

In effect, the commission reverted to a traditional approach for addressing PLR customers. This regulatory treatment was a temporary solution to the problem and now no longer applies. The future treatment of the PLR role is not yet determined.

During the summer of 2000, the CPUC adhered to the legislation by allowing customers to bear the commodity price risk associated with generation. Unfortunately for customers, generating prices in California have risen significantly due to greater regional usage and reduced regional capacity causing, in some cases, a doubling of customer's bills for certain summer months. Clearly, higher electric prices was not an expected outcome of deregulation so many of the architects of deregulation including members of the commission, the legislature and certain consumer groups have responded to this development by proposing a variety of solutions, including re-regulation.

The Pennsylvania Case Study

Retail choice for generation began on January 1, 1999 for all customers in Pennsylvania. Through June 1, 2000, the state's electric utilities were to retain their PLR responsibility, providing default service for all customers.

The Pennsylvania Public Utility Commission (PPUC) conducted a competitive bidding program to phase in the competitive provision of PLR service: 20% of retail customers on June 1, 2000; 40% on June 1, 2001; 60% on June 1, 2002; and 80% on June 1, 2003. PLR service from any supplier will be subject to the generation rate cap. If no bids are received at or below the Pennsylvania electric utilities' generation rate cap, the utilities will furnish PLR service at the rate-cap levels.

On February 3, 2000, Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec), both operating subsidiaries of GPU, Inc., filed a report with the PPUC stating that they had received no bids from alternative generators to supply power to their default customers in Pennsylvania. These default customers are primarily residential and small commercial customers. The two operating utilities divested all of their generating assets recently, as part of GPU's competitive strategy to remain in the regulated transmission and distribution business. Now Met-Ed and Penelec must purchase sufficient capacity to furnish PLR service.

Based on the June 1998 restructuring order, these two companies can only charge their default customers at the generation rate-cap levels, regardless of what they are paying to purchase the power supply. The companies have been working with the PPUC to find a solution and a collaborative is expected to issue a report in the near term.

Moody's expects that the PPUC will be required to address any purchased power costs above the rate-cap levels that the GPU subsidiaries are incurring. As in the case of the Illinois utilities, if Met-Ed and Penelec cannot recover from their default customers the purchased power costs above the pre-determined generation rate-cap rates they will suffer earnings and cash flow erosion during the period in which they are honoring their service obligation as default provider.

Illinois – A Problem Waiting to Happen?

Several Illinois utilities now operating under electric transition plans may be exposed to supply risk during the summer of 2000. The Illinois electric restructuring plan requires each year that a third party consultant determines the market generation component of the standard offer rate. The consultant set the current generation component at an artificially low level resulting in a very low standard offer rate. This potential risk is exacerbated by the fact that, because of market uncertainty and volatility, not many customers have selected choice.

Compounding the problem, the Illinois legislation eliminated the fuel adjustment factor, which means that rates that utilities can charge customers are fixed. Given the tight capacity market in the Midwest, a warm summer could lead to new price spikes which, given the rate cap, could affect some of the Illinois utilities financially. All of the utilities have initiated proceedings to modify the process for determining the market generation price, replacing the existing 'neutral fact finder' methodology. Additionally, most utilities have maintained rights to sufficient supply through PPA structures to mitigate exposure to volatile market conditions.

Special Comment Credit Implications of Power Supply Risk

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Outside the US, please call 1.212.553.1658.
Report Number: 58449

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.

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Rob Hornick, Ellen Lapson, and Donna DiDonato

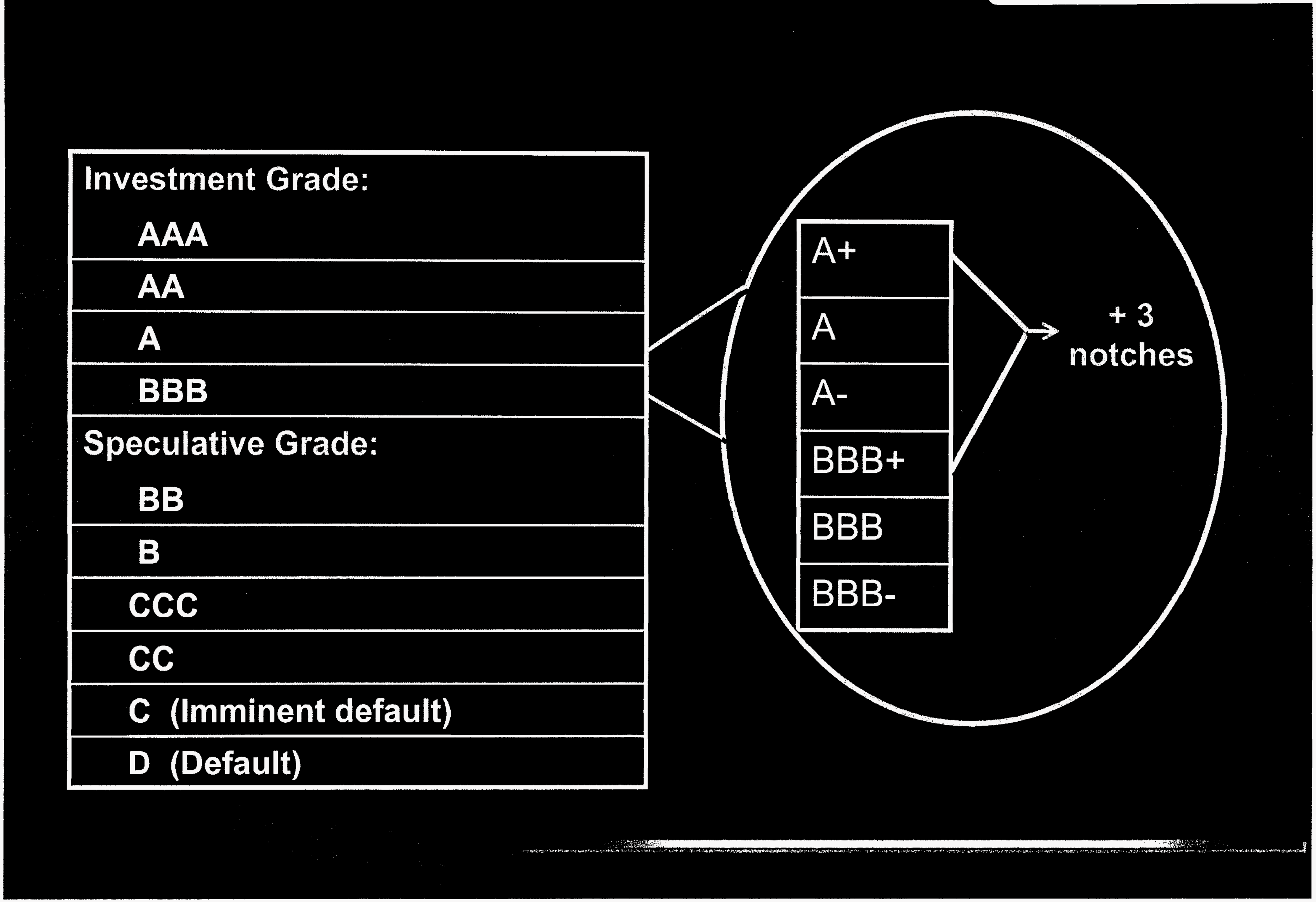
Global Power

- **Background on the Rating Process**
  - Committees, Ratings & Outlooks
  - Notching
- **Analytical Methods**
  - Financial Ratio Targets
  - Projections Analysis
  - Absolute versus Relative Analysis
  - Liquidity

- **Off Balance Sheet & Other Debt-Like Obligations**
  - Operating Leases
  - Tolling Arrangements
  - Synthetic Leases
  - Purchased Power Agreements
  - Corporate Guarantees
- **Hybrid Securities**
- **Use of Fitch Energy Price Forecasts**

- **Committee Presentation**
  - Annual and Periodic Reviews
  - Event or Scenario Analysis
- **Trend Designations**
  - Outlooks identify direction of ratings
    - Stable, Positive or Negative
  - Watches are generally associated with events and supercede Outlooks
    - Positive, Negative or Evolving
  - Rating actions are not limited by Outlooks or Watches

- **Appeal Process**
  - Generally limited to new information
  - Time is of the essence
  - Watch status or Outlook generally not up for debate.
- **Press Releases & Reports**
  - Rating actions (including outlook changes and watch listings) are disseminated in a press release.
  - Advance copies of press releases and reports are generally provided to the issuer for comments limited to issues of factual accuracy or elimination of non-public information.


Investment Grade:
AAA
AA
A
BBB
Speculative Grade:
BB
B
CCC
CC
C (Imminent default)
D (Default)
A+
A
A-
BBB+
BBB
BBB-
+ 3 notches

- **Financial Ratios and Targets**
  - Fitch uses some benchmark financial ratios internally, but generally doesn't publish them.
  - Primary financial ratios are defined in the Financial Peer Study attached as Exhibit A.
- **Projection Analysis**
  - Fitch analysts are required to develop an independent view of an issuer's financial prospects and to compare the Fitch forecast to management projections.
  - Stress scenarios are specifically tailored and incorporate possible negative outcomes – unfavorable regulatory decisions, etc.

- **Absolute versus Relative Analysis**
  - While issuers are evaluated independently, industry conditions and performance relative to peers is also considered.
  - This could include evaluation of financial measures, business strategy and performance, and quality of management.
- **Liquidity**
  - Targets for liquidity take into consideration the historic volatility of operating cash flow, potential working capital and collateral needs, plant outages for integrated utilities and regulatory lag.
  - Liquidity requirements for future capex and debt maturities depends on business risk, rating level, and capital markets access.

For purchased power agreements, operating leases, tolling arrangements, and synthetic leases, Fitch policy varies from GAAP accounting rules in order to capture operating leverage.

- Primary emphasis is identifying risk, and if appropriate, capitalizing a debt like obligation.
  - Two important concepts are:
    1. Whether an issuer has a high likelihood of recovering costs under the contract from ultimate consumers (or another counterparty).
    2. Whether the contract is in-the-money or out-of-the-money based on Fitch's Base Case and Low Gas Case projection models.

Mark to Model Value	Low	High
Out of the $$	**High Risk** Potential earnings and cash flow impact.	**Moderate Risk** Certainty of recovery limits risk.
In the $$	**Moderate Risk** Need to monitor for change in value and counterparty credit risk.	**Low Risk** Counterparty credit risk is still an issue.

Likelihood of Cost Recovery

- **Power Purchase Agreements**
  - In cases where there is limited information, assume 30% of total payment is capacity and capitalize that amount.
  - Where sufficient information is available, the MTM value of the contract is determined based on Fitch's market forecast.
  - The amount capitalized is affected by amount of risk attributed to recovery:
    - Contractual offsets and counterparty credit quality.
    - Level of regulatory support and recovery mechanisms.
    - QF contracts are deemed to be relatively low risk.

- **Operating Leases**
  - Fitch policy dictates that operating leases should be capitalized using one of two primary methods – a multiple approach or a PV calculation of the minimum lease rent.
- **Tolling Agreements**
  - Power plant tolling arrangements are treated in the same manner as operating leases for the purchaser of the toll with the PV of the capacity payments capitalized.
- **Synthetic Leases**
  - If the lessor is an SPE, then the entire SPE is consolidated into the lessee.
  - If not, the lease obligation is valued based on the PV of payments plus residual value guarantee.

- **Non-Recourse Debt Obligations**
  - Non recourse debt obligations are evaluated in terms of the strategic relevance of the asset or business unit and the level of financial and legal separation and can be deconsolidated.
  - When a unit is determined to be ”off credit” and debt is deconsolidated, all income and dividends from the unit must be excluded from projections.

- **Corporate Guarantees**
  - **Guarantees of Debt**
    - Guaranteed debt of non-consolidated entities is consolidated.
  - **Performance Guarantees** (currently under review)
    - Current Method: Nominal amount of guarantees times x% (e.g.,10% of nominal)
    - Proposed: Fitch is considering whether to apply the standard of FIN 45 not only to new performance guarantees issued after January 1, 2003, but also to pre-existing guarantees.
      - Will issuer's provide sufficient disclosure?
      - How long will it take for pre-existing guarantees to roll over?

- Fitch's evaluation of hybrid securities focuses on the flexibility the instrument provides –
  - Required payment of dividends or interest
  - Terms of ultimate repayment of principal
  - Priority in bankruptcy
- Each security can be analyzed and classified on an equity-debt continuum with "equity credit" based on established ranges in Fitch's hybrids criteria.
- Not affected by GAAP accounting treatment.
- See Exhibit D for further details.

- Fitch uses a model provided by an outside consultant to forecast market clearing prices of power in 5 main regions and 70 sub-regions.
  - The current base case forecast assumes long term gas prices of $3.50 (in constant 2003 dollars)
  - The current low gas case forecast assumes long term gas prices of $2.50 (in constant 2003 dollars)
- Financial Projections incorporate expected revenues from merchant assets based on energy price forecasts.

A	Financial Peer Study
B	Corporate Rating Criteria
C	Credit Update Report Guidelines
D	Hybrid Securities: Evaluating the Credit Impact
E	Rating Linkage Within US Utility Groups: Ring-Fencing Mechanisms
F	Operating Leases: Implications for Lessees' Credit
G	Synthetic Leasing

www.fitchratings.com