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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE LANGLEY GULCH POWER PLANT.	))))))	CASE NO. IPC-E-09-03

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

LORI SMITH

Q. Would you please state your name, business address, and present occupation?

A. My name is Lori Smith and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company ("Idaho Power" or "Company") as Vice President of Corporate Planning and Chief Risk Officer.

Q. What is your educational background?

A. I graduated in 1983 from Boise State University, Boise, Idaho, receiving a Bachelor of Business Administration degree in Information Sciences. In 1999, I was awarded the designation of Chartered Financial Analyst. In 2008, I completed a two-part course in Decision Analysis and Decision Quality in Organizations at the Stanford Center for Professional Development. I have also attended numerous seminars and conferences related to utility accounting, corporate finance, and risk related topics.

Q. Would you please outline your business experience?

A. From 1983 to 1986, I was employed by Idaho Power Company and assigned to the Materials Management Department. From 1986 to 1994, I served as a Financial Accountant and later as a Budget Accountant. I was promoted to Business Analyst in 1994. In 1996, I was promoted to Strategic Analysis Team Leader. In 2000, I assumed the position of Director of Strategic Analysis. In 2003, I was named Director of Strategic Analysis and Risk Management. In 2004, I was promoted to the position of Vice President of Finance and Chief Risk Officer. In 2008, I assumed my current position as Vice President of Corporate Planning and Chief Risk Officer.

Q. What are your duties as Vice President of Corporate Planning and Chief Risk Officer?

A. My responsibilities include the oversight of corporate development, strategic planning, and risk management processes for Idaho Power Company. Corporate development includes acquisitions, divestitures, and joint-ventures. Strategic planning includes development of analyses, strategies, and operating plans. Risk management includes activities related to managing market, credit, and operational risk exposure from an enterprise perspective.

I am tasked with ensuring the best use of Idaho Power's resources by defining and planning the Company's strategic and long-range goals. I am also responsible for the analysis of the financial impacts of regulatory strategy to ensure successful implementation and provide meaningful insight into strategic alignment. I direct the development of operational forecasts and analysis both long- and short-term. In addition, I am the corporate board representative for Ida-West Energy and IDACORP Financial Services. I have subsidiary leadership responsibilities that include setting goals and defining investment criteria and performance requirements. I direct the activities related to the organization's market risk and credit exposure to protect against adverse movements in net power supply costs. Finally, I am responsible for designing, developing, and implementing an Enterprise Risk Management process for IDACORP, Inc., and Idaho Power Company.

Q. What is the purpose of your testimony in this proceeding?

A. I describe how Idaho Power's need for capital to fund infrastructure and maintenance investments over the next three years exceeds the cash flow it receives from operations. It will be very difficult for Idaho Power to finance the Langley Gulch power plant with debt or equity given the current conditions in the capital markets, the restructuring of which has resulted in limited availability of credit and devalued stock prices. Given these adverse economic conditions, I believe the proposed recovery of CWIP in rate base annually or the regulatory ratemaking assurances described in Mr. Ric Gale's testimony will minimize Idaho Power's need to access the capital markets and/or make the Company more attractive to lenders if it does.

IDAHO POWER'S NEED FOR ADDITIONAL CAPITAL

Q. What is Idaho Power's current ability to fund plant investments required to meet its customers' energy needs over the next three years?

A. Idaho Power has been diligent in its efforts to continue to meet the energy needs of its customers. This has been demonstrated in the Company's Integrated Resource Plan ("IRP"), the most recent of which was filed in 2006 and updated in June 2008. The IRP has identified the need for a baseload resource to come on-line in 2012. As Mr. Karl Bokenkamp describes in his testimony, the 330 MW Langley Gulch power plant project ("Project") identified through the competitive bidding process will meet the growing customer demand for electricity in 2012. However, the expenditures associated with this Project combined with the continued needs to upgrade existing facilities, expand environmental controls, and maintain an aging infrastructure, require the Company to expend a significant amount of capital in order to meet these needs.

These capital requirements come at a time when the Company's balance sheet has been weakened due to the impacts of drought conditions in six of the last seven years and much higher historical capital expenditures since 2006 to meet the demands of customer growth. The cost of the new infrastructure, to be built concurrently with current maintenance capital expenditures, substantially exceeds Idaho Power's cash flow from operations.

Q. What is cash flow from operations?

A. A simple measure of cash flow from operations is seen in the average of depreciation expense plus net operating income, a proxy for cash flow from operations. During the time period 2006 through 2008, Idaho Power Company generated on average approximately $190 million of cash flow from operations. The average of construction expenditures during this time was $250 million. The shortage of internally generated cash flows versus Idaho Power's infrastructure investments, on average, from 2006-2008 is $60 million per year. The additional construction expenditures above cash flow from operations must be acquired from the capital markets in a balanced combination of long-term debt financing and issuances of common stock.

Q. What is the impact of inadequate cash flows?

A. Inadequate cash flows cause credit rating agencies to be concerned. The credit rating community uses cash flow and other financial ratios with more subjective evaluations, such as perceived regulatory support, to assess the financial health and prospects for a utility. If changes in such measures exceed a rating agency's thresholds, such changes can affect bond ratings. Bond ratings, in turn, directly affect both the cost and the availability of debt, which are both important components in determining the utility cost of capital.

Q. How much capital does the Company expect to invest in its system over the next three years?

A. As reported on February 26, 2009, in IDACORP's and Idaho Power's FORM 10-K, the Company expects to spend between $220 and $230 million in 2009 and average from $278 million to $295 million between 2010 and 2011 **excluding** the investment in the 2012 Langley Gulch Project. The expected investment requirements to reliably maintain and operate the system impose additional pressure on cash flow coverage ratios during the next three years absent a significant increase in operating cash flows.

Q. What is the impact of this shortage of cash flow from operations?

A. The shortage must be financed with funds raised in the capital markets. The Company must acquire long-term debt and have the ability to issue common stock in order to make the required investments related to providing reliable service. Given the current state of the capital markets, Idaho Power has limited ability to access the capital it needs to finance construction of the Langley Gulch Project and cannot predict when the market may return to "normal."

CURRENT STATE OF THE CAPITAL MARKETS

Q. What is the current state of the capital markets?

A. The current credit crisis in the capital markets can be characterized by significant credit contraction as a result of the fundamental restructuring of the financial sector. This restructuring is evidenced by fewer banks, increased regulatory requirements for capital adequacy, and significant new requirements to de-leverage bank balance sheets from their historical leverage multiples of up to 30 times. Since Labor Day 2008, there have been unprecedented market events from the credit contraction, including the U.S. Treasury's efforts to stabilize the U.S. banking industry by providing $350 billion through the Troubled Asset Relief Program ("TARP"). The U.S. Treasury's critical objectives are to stabilize the financial markets and reduce systemic risk, support the housing market by avoiding preventable foreclosures and facilitate mortgage finance, and to protect taxpayers. To this end, the U.S. Treasury has thus far allocated a total of $700 billion in the Emergency Economic Stabilization Act, including the TARP funding.

Idaho Power has long-term banking relationships, a high percentage of which are with banks that have received TARP funding from the U.S. Treasury. These relationships are in good working order; however, it is unknown whether the market will be receptive to the Company's financing needs when Idaho Power is ready to access the capital markets. This access to capital markets cannot be predicted at this time. The collapse of the credit markets reduced the number of banks providing liquidity as a result of bank failures, government interventions, and Mega mergers. The result is increased volatility, increased de-leveraging, and de-risking by the U.S. banking industry.

Q. Why is access to the capital markets so important to this proceeding?

A. Idaho Power cannot internally fund the required investment in plant, including the Langley Gulch Project, necessary to reliably serve customers from its existing operations. The impact of this crisis significantly increases the value of an investment grade credit rating as the lending capacity of the financial industry contracts and the selection criteria for borrowing companies is more stringent. It is critical that our continued efforts to maintain Idaho Power's corporate credit rating of BBB with S&P and Baa1 with Moody's are successful.

Q. Why is Idaho Power's ability to maintain its credit rating paramount in this uncertain credit environment?

A. Maintaining our current credit rating minimizes the interest rate spread between different rating grades (investment grade versus below investment grade) and allows the Company to access long-term maturities of debt. The alternative would be to finance long-lived assets with short-term duration bonds that subject our customers to interest rate risk in the form of durations for bonds that do not match the life of the asset.

For investment grade issuers, like Idaho Power, the credit spreads (i.e., the yield spread, or difference in yield between different securities due to different credit quality) for issuers were at an all time low in 2005. This relatively inexpensive liquidity and ability to access long-term capital changed in October 2008 to a capital market with short supply, with liquidity being non-existent or very hard to obtain. The cost of funding across the capital structure increased for short-term and long-term debt and the reduction in stock market values decreased the overall ability to raise capital. Some companies that currently have a credit rating below investment grade have experienced complete exclusion from the market place from October 30 through December 9, the longest period without new issuance in 17 years. Additionally, issuers are reluctant to launch a transaction without a high degree of certainty around its success because of the negative publicity associated with failed transactions. The increase in credit spreads as a result of the rapid deterioration in the U.S. banking industry and corporate credit markets brought a historic wholesale widening of credit spreads and a slowdown in supply of credit to high-grade issuers. The market access to BBB issuers, like Idaho Power, has improved but access still remains credit specific, volatile, and unpredictable.

The Company's access to credit at reasonable costs, desired maturity of issue, and reasonable financing terms is greatly dependent on the investment grade rating currently in place.

Q. How do major credit rating agencies determine Idaho Power's credit profile?

A. The credit rating agencies begin their assessment using a variety of financial ratios. The calculation of these ratios varies between credit rating agencies. In addition, the credit rating agencies evaluate certain qualitative factors, including the regulatory environment, management capability, and past operational and financial performance. Please see Exhibit No. 5 for the most recent Moody's and S&P publications on Idaho Power Company.

Q. In the event the Commission selected a different alternative to the Project, do credit rating agencies view credit risk for purchase power agreements or tolling agreements differently than a plant built by a utility?

A. No. When a company decides to buy generation thru a long-term purchase power agreement or a tolling arrangement there is a risk transfer from the seller of the energy to the buyer of the energy and its customers and shareholders in the form of imputed debt. Imputed debt is a measure of financial risk shifted to a utility when it enters into a purchase power agreement ("PPA") or tolling agreement ("TA"). The imputed debt measurement is calculated by S&P, for example, and included in the analysis of financial ratios used to measure the utility's creditworthiness. Because debt, actual or imputed, is attributed to the utility that acquires power through the construction of a new plant, PPA or TA, regulatory support is needed to mitigate the impact on the utility's financial ratios. The mitigation can take the following forms:

1. Full and automatic regulatory support which can reduce the financial risk imposed on a utility from imputed debt by decreasing or eliminating the uncertainty regarding full recovery of the costs of the PPA.

2. Compensate the utility for the increased financial risk by

a. Increasing the amount of equity in the rate base, and/or

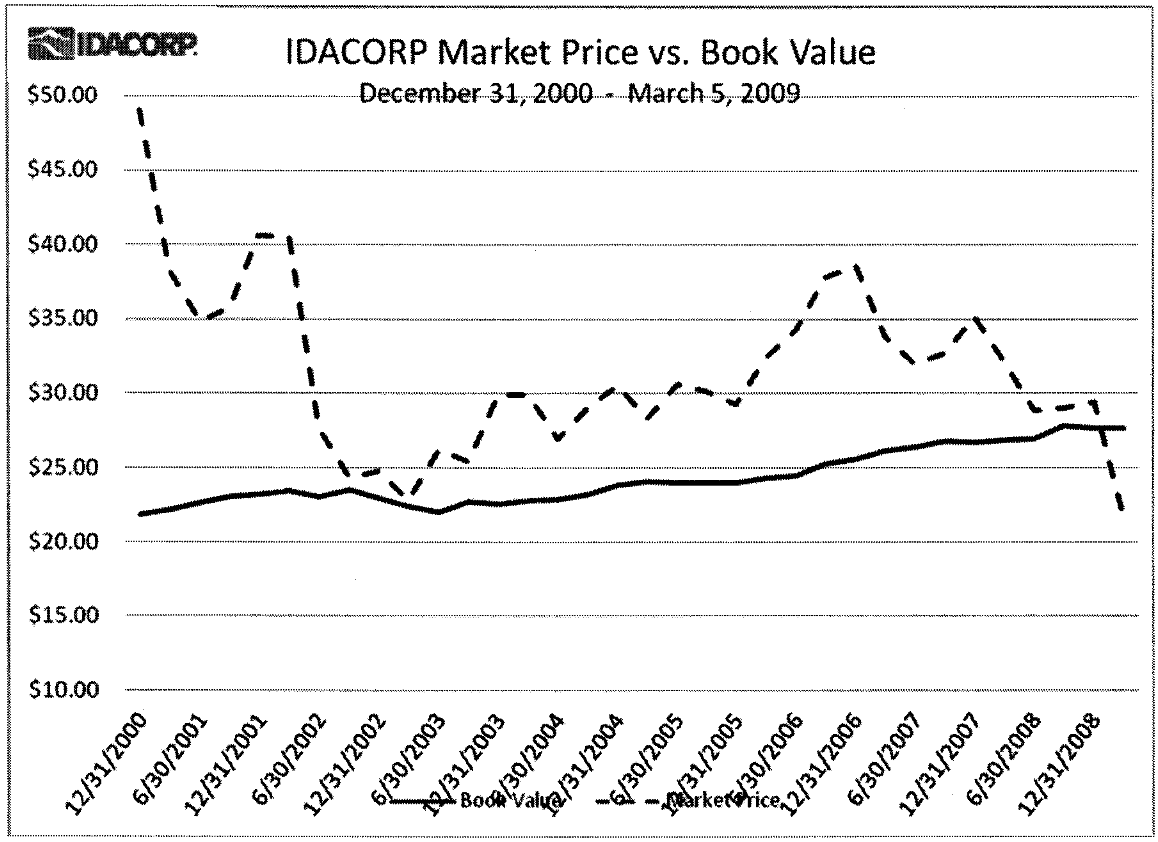
b. Increasing the allowed return on equity, and/or

c. Restoring financial ratios to pre-PPA or TA level with an adder to the PPA payment.

To further explain the ramifications of imputed debt on utilities, I have included a white paper written by the Brattle Group for the Edison Electric Institute and regulatory staff called "Understanding Debt Imputation Issues" as Exhibit No. 6.

Q. What are the risks of issuing common stock during times when the market value of the stock is below its book value, as Idaho Power's stock currently is?

A. The Company's stock has deteriorated in value by 25.4 percent from December 2008 to March 5, 2009. The Company has not seen a decline of this magnitude since late 2000 in which IDACORP's telecommunications and energy marketing affiliates helped drive down IDACORP's stock price. Evidenced below is a chart of IDACORP's trading history since the end of 2000. The market value of IDACORP's stock is trading below book value at a time when the Company needs to raise capital to finance the construction of the Project. A corporation's book value is used in fundamental financial analysis to help determine whether the market value of corporate shares is above or below the book value of corporate shares. Issuing new equity below book value will cause dilution of existing shareholders and invites shareholder lawsuits.



RELIEF REQUESTED

Q. Mr. Gale's testimony describes the Company's ratemaking request in the form of two alternatives: (1) recovery of a portion of Construction Work in Progress ("CWIP") the Company incurs as it constructs the Project to be included in current rates on an annual basis or (2) explicit findings on how the Commission intends to treat the Company's Langley Gulch investment for ratemaking purposes at the time it is placed in service. How would the financial community view each of these alternatives?

A. The Project is expected to take four years to construct and require significant funding from the capital markets in terms of both debt and equity at a time of substantial uncertainty related to accessing the capital markets. CWIP, including AFUDC, in rate base during construction will provide cash flow to construct the Project. This new cash flow will reduce the Company's need to access the capital market at a time of great volatility and unpredictable access.

It is my belief that financing the construction of the Project without regulatory assurance of rate recovery or CWIP in rate base will endanger Idaho Power's ability to maintain its current credit ratings. CWIP in rate base would be a substantial benefit from a credit perspective because cash would be collected currently versus the assurance of cash collected in the future.

Q. If the Commission approves AFUDC and CWIP in rate base, how does Idaho Power envision these accounts would operate?

A. AFUDC is the capitalization costs associated with the construction of an asset, whereas CWIP is the accumulation of all costs associated with the construction of an asset plus the cost of financing the construction expenditures. AFUDC provides for the financial carrying costs of an asset while it is being constructed and is recorded in Account 107. During construction, AFUDC is a non-cash entry to Account 107 that represents the costs of debt financing and an equity return as proscribed in the FERC formula (CFR 18, Part 101, Subchapter C, Electric Plant Instruction 3 (A) (17), as amended by a FERC letter dated December 30, 1981). The AFUDC plus the accumulation of all other costs associated with construction is then closed to plant Account 101 as an asset upon completion of the project.

Once included in rate base, AFUDC is typically recovered over the life of the asset through depreciation expense and a return on investment earned. The asset and AFUDC generate cash flow for the Company when included in rate base in a revenue requirement proceeding.

Q. What benefit would the ratemaking assurances and CWIP recovery mechanisms provide to Idaho Power customers?

A. With CWIP, customers will help fund construction of the Langley Gulch power plant as it is built, thus avoiding financing costs that would otherwise be depreciated over several decades. As with buying furniture or a vehicle, paying for a power plant upfront with cash is significantly less expensive than financing it through debt or equity.

CWIP in rate base reduces the rate shock experienced by our customers by smoothing the rate increases over the construction period versus a one-time large increase at the end of the construction period. I will describe for illustrative purposes an example that estimates the customer impact of three recovery alternatives.

In Exhibit No. 7 I have compared two of the alternative rate recovery examples to a traditional plant closing to a plant filing of the Langley Gulch power plant, with ratemaking assurances described in Mr. Gale's testimony resulting in a rate increase of 7.9 percent over current rates in early 2013. The first comparison example, "AFUDC: Pay Currently," is similar to Hells Canyon Relicensing AFUDC granted in Order No. 30722. If customers pay currently for AFUDC from 2010 to 2013, the cumulative increase at the end of construction period would be 6.9 percent, comprised of a 1.9 percent, 1.9 percent, 1.1 percent, and 2.0 percent increase for the years 2010, 2011, 2012, and 2013, respectively. The key difference between this method and the "CWIP Rate Base" method is that a regulatory liability is established to collect and amortize the collection over the life of the plant.

In the second example, "CWIP in Rate Base," customers paying for all CWIP expenditures including AFUDC would experience an estimated increase of 7.0 percent. The CWIP in Rate Base example is comprised of a 1.9 percent, 2.0 percent, 1.4 percent, and 1.8 percent rate increase in the years 2010, 2011, 2012, and 2013, respectively. These examples demonstrate how the rate increases will be softened and will allow customers time to adjust to the increasing rates versus a one-time rate increase that is preliminarily estimated to be 7.9 percent over current rates beginning in 2013.

Q. Will the inclusion of CWIP in rate base or ratemaking assurances guarantee access to the debt and equity capital markets?

A. Answering this question with any specific level of certainty is made more difficult in the current climate of unprecedented bank failures, the speed of the economic downturn, continued capital market uncertainty the contraction of available financing capacity which has shrunk the once liquid and deep capital markets that Idaho Power has been able to access in the past. However, I believe the granting CWIP for all or a portion of the Company costs for construction of Langley Gulch and ratemaking assurances as described by Mr. Gale in his testimony are the kinds of regulatory support mechanisms that will help to differentiate Idaho Power from other capital-seeking companies when the construction and permanent financing of the Project is required.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-03

IDAHO POWER COMPANY

SMITH, DI
TESTIMONY

EXHIBIT NO. 5

Moody's Investors Service

Global Credit Research
Credit Opinion
4 JUN 2008

Credit Opinion: Idaho Power Company

Idaho Power Company

Boise, Idaho, United States

Ratings

Category	Moody's Rating
Outlook	Negative
Issuer Rating	Baa1
First Mortgage Bonds	A3
Senior Secured	A3
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured Shelf	(P)Baa1
Commercial Paper	P-2
Parent: IDACORP, Inc.	
Outlook	Negative
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured MTN	Baa2
Commercial Paper	P-2

Contacts

Analyst	Phone
Kevin G. Rose/New York	212.553.0389
William L. Hess/New York	212.553.3837

Key Indicators

[1]
Idaho Power Company

	LTM 1Q 08	2007	2006	2005
(CFO Pre-W/C + Interest) / Interest Expense	2.3	2.4	3.3	3.4
(CFO Pre-W/C) / Debt	7%	7%	13%	13%
(CFO Pre-W/C - Dividends) / Debt	3%	3%	8%	8%
(CFO Pre-W/C - Dividends) / Capex	13%	14%	41%	42%
Debt / Book Capitalization	46%	45%	42%	41%
EBITA Margin %	18%	19%	20%	17%

[1] All ratios calculated in accordance with the Global Regulated Electric Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Idaho Power Company (IPC) is a vertically integrated regulated investor-owned utility and the principal wholly-owned subsidiary of IDACORP, Inc. (IDA), a holding company which also serves as parent for other modest-sized non-utility businesses. As an all-electric utility, IPC provides retail electric service to approximately 483,000 residential, irrigation, commercial and industrial customers within a 24,000-square mile service area encompassing southwestern Idaho and eastern Oregon. The company operates a system with 4,747 miles of transmission lines and 26,394 miles of distribution lines. IPC relies heavily on hydro-electric power for its generating needs, normally generating nearly half of the electricity it sells from 17 hydro-electric developments on the Snake River and its tributaries. IPC also serves a portion of its electric load from three coal-fired power plants in Wyoming, Nevada, and Oregon and from the natural gas-fired Bennett Mountain Power Plant, Danskin 1 Power Plant, and Evander Andrews Power Complex in Mountain Home, Idaho. IPC is the parent of Idaho Energy Resources Co., a joint venture partner in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC. The utility also buys electricity from the regional wholesale market to meet its customers' needs for electricity.

On a stand-alone basis, IPC represents the substantial majority of IDACORP's consolidated revenues, net income, and assets. IPC's customers have been weighted toward the residential class, with about 46.1% of 2007 general business revenues derived from sales to residential customers, which are typically more predictable and stable sources of revenue. We do not expect this to change materially in the foreseeable future. The remainder of IPC's 2007 revenues were derived from electricity sales to commercial customers (25.4%), industrial customers (15.2%), and irrigation customers (13.3%).

IPC's retail rates are subject to the regulatory jurisdiction of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC) as it relates to rates charged to its retail customers and various financing activity. Wholesale activities and interstate activities are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Recent Events

Effective June 3, 2008, Moody's affirmed the ratings of IDACORP, Inc. (Baa2 Issuer Rating and Prime-2 short term debt rating) and its regulated utility subsidiary, Idaho Power Company (IPC; Baa1 senior unsecured and Prime-2 short-term debt rating). At the same time, Moody's changed the rating outlook to negative from stable for both companies. See Press Release of June 3, 2008 for additional commentary.

Rating Rationale

Key factors affecting IPC's Baa1 senior unsecured debt rating include a relatively low business risk profile and low cost structure relative to national peers within a usually generally supportive regulatory environment combined with an increasing level of capital expenditures to add generation capacity, transmission infrastructure, and address other asset maintenance to ensure meeting service safety and reliability standards. The company's recent financial metrics, including its coverage of interest and debt by cash flow from operations exclusive of working capital changes (CFO Pre-W/C), have been pressured to a level we often see for a regulated electric utility in the Ba rating category. These recent metrics are the result of unfavorable hydro conditions and the adverse effects the recent increase to the load growth adjustment rate (LGAR) has had on net power supply cost recovery under the power cost adjustment (PCA) mechanism. With respect to the latter concern, we note that the LGAR subtracts the cost of serving additional Idaho retail load from the net power supply costs that IPC is allowed to include in its annual PCA filing. We address the LGAR in more detail below; however, as IPC continues to diversify its resource portfolio and works with the IPUC to adjust or replace the current LGAR, as called for as part of the settlement of the utility's last general rate case, we are concerned about whether recent revenue increases approved by the IPUC and the OPUC, when combined with the likely implementation of further general rate increases associated with future rate filings, will be sufficient to allow IPC's cash flow coverage metrics to revert back to levels more consistent with the current rating over the next 12 to 18 months. Meanwhile, IPC's Integrated Resource Plan (IRP), and its access to sufficient liquidity are considered in line with the Baa rating category. IPC's ratings also take into account that IPC's retail rates remain below national averages, and that it is pursuing strategies to control operating expenses and conservatively finance its investments.

The most important drivers of IPC's current ratings and outlook are as follows:

DETERIORATION IN HYDRO CONDITIONS RAISES OPERATING CHALLENGES AND PRESSURES MARGINS

During 2007, there was a return to the drought conditions that have persisted in Idaho in all but one of the last seven years. The one exception was in 2006, when there was a brief normalization of water levels. Inflows into the company's largest storage reservoir, the Brownlee Reservoir, were only 2.8 million acre feet (maf) during the critical April through July 2007 runoff period, which was about 44% of average. Although hydro conditions are somewhat better to date in 2008, they still remain below normal. The current expectations for runoff during the critical April through July period in 2008 of about 4.8 maf is still only about 76% of average. Based on this data, IPC is currently expecting to generate between 6.0 and 8.0 million megawatt hours (MWh) from its hydroelectric facilities during 2008, compared to 6.2 million MWh in 2007. The water conditions in the Snake River Basin this year have enabled IPC's hydro-electric generation to contribute about 46% of total system generation during the first quarter, compared to about 51% for the same period in 2007. When IPC experiences poor hydro-electric generating conditions, it results in a heavier dependence on typically more expensive thermal generation and purchased power, and reduces wholesale sales while increasing operations and maintenance expenses and pressuring margins.

It remains to be seen whether the drought conditions that have persisted for six out of the last seven years in the U.S. Pacific northwest region may be viewed as an anomaly or as part of a larger more permanent or semi-permanent climate shift that signals the need for reduced reliance upon hydro-electric generation for a company such as IPC that has relied fairly extensively upon hydro as the primary component of its generation portfolio. Moody's ratings and negative outlook for IPC take into account these increased operating challenges.

PARTIAL OFFSETS FROM POWER COST ADJUSTMENT (PCA) MECHANISM

Our ratings also take into consideration the long-standing existence of a PCA mechanism in Idaho and the generally supportive outcomes in annual filings made before the IPUC. Under the terms of the PCA, IPC annually adjusts its rates charged to Idaho retail customers for 90% of the difference (with interest) between the actual and forecasted costs of fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. We generally view the existence of PCA mechanisms to be beneficial to a utility's overall credit profile because such a mechanism can help minimize the negative effects on earnings and cash flow when net power supply costs unexpectedly exceed forecast levels in existing rates. This is especially so when the cash recovery period is relatively short. We note that IPC's 2008-2009 PCA filing initially requested an increase of $87.2 million to the PCA component of customers' rates. Subsequent to this request, the IPUC issued a ruling that required IPC to offset the PCA request with $16.4 million of proceeds from an earlier sale of sulfur dioxide emission allowances. As a result, it was expected that IPC's PCA rate increase, to be effective June 1, 2008, would be $70.7 million (10.4%) for the 2008-2009 period. In a final PCA decision rendered May 30, 2008, the IPUC made positive adjustments that brought the approved level of the PCA rate increase effective June 1, 2008 to $73.3 million (10.7%).

IPC HAS BEEN ACTIVE IN FILING GENERAL RATE CASES

On the heels of the 3.2% general rate case settlement increase to IPC's Idaho retail base rates implemented on June 1, 2006, which we generally viewed as a particularly encouraging sign of a more transparent working relationship between the IPUC and IPC, the utility filed another general rate case on June 8, 2007. In the June 2007 filing, IPC sought a 10.35% rate increase ($63.9 million annually), to address recovery of and return on investments and to also compensate for higher operating costs. IPC also requested that the IPUC reduce the LGAR to $29.16 per MWh from $29.41 per MWh. As described in public filings, the significance of the LGAR is that it adjusts IPC's net power supply costs that it includes in the annual PCA filings for differences between actual load and the load used in calculating existing base rates. During periods of modest load growth and/or when there is little difference between assumed and actual load, the LGAR is a less material issue; however, in recent periods, IPC's loads have grown considerably in excess of the assumed load in setting base rates. During such periods, the marginal energy cost of serving new Idaho retail customers are subtracted from the PCA filings. In effect, IPC must wait until its next general rate case to adjust the assumed load growth. From a credit perspective, Moody's concerns increase when the IPUC increases the LGAR and/or there is a significant mismatch between the assumed and actual load growth because of the potential negative effects on IPC's earnings and cash flow under those circumstances.

As the June 2007 case proceeded, the parties settled in January 2008 on an average annual 5.2% rate increase (about $32.1 million) and agreed to pursue good faith efforts to develop a mechanism to adjust or replace the current LGAR. Importantly, the general rate case settlement gave IPC an opportunity to reset the load growth assumption used in the rate process. Meanwhile, the settlement provided for use of the IPUC staff recommended LGAR of $62.79 per MWh, which would only be applied to half of the load growth in Idaho during each month within the April 2008 - March 2009 PCA year. Another important aspect of the settlement called for good faith discussion among the parties aimed at establishing acceptable terms for use of a forecast test year in future general rate cases which, if implemented, would address concerns about regulatory lag and be viewed as a credit positive. The settlement was ultimately approved by the IPUC in the form presented to them and new rates that were silent as to the allowed rate of return became effective March 1, 2008. (See below for further background on future general rate case plans).

OTHER REGULATORY INITIATIVES

Aside from the recently concluded PCA filing and other general rate case activity in Idaho, IPC recently wrapped up a series of other proceedings in Idaho and Oregon in May 2008, which collectively will provide an additional $18.4 million of revenue under rates that took effect June 1, 2008 and should contribute to a rebound in financial results. First, the IPUC approved IPC's request for a 1.4% rate increase ($9 million) to address recovery of the Danskin 1 natural gas fired plant that began commercial operation earlier this year. The IPUC also approved IPC's requested increase in its Energy Efficiency Rider to 2.5% from 1.5%. This 1% increase translates into about a $7 million annual increase in revenue that will be collected from its Idaho customers to cover the costs of various energy efficiency programs. Furthermore, IPC will make its first rate adjustment under the decoupling program in Idaho aimed at de-linking revenues from volume. The net effects of the IPUC approval of this filing results in a $2.4 million rate reduction. Lastly, the OPUC approved a $4.8 million rate increase (15.7%), representing the first rate adjustment under the recently implemented power cost adjustment mechanism in Oregon. Approval of the rate change is, however, subject to refund. We understand that the OPUC staff requested additional time to further review data since this was the initial proceeding under this mechanism and the relative amount was quite large. Nevertheless, there was a desire to implement a rate adjustment effective June 1, 2008.

SIGNIFICANTLY HIGHER UTILITY CAPITAL EXPENDITURES REQUIRE EXTERNAL FUNDING

IPC faces significantly higher capital expenditure needs over the next few years for additions and upgrades to existing generation, transmission, and distribution infrastructure, primarily to meet customer and demand growth. IPC expects to continue financing its large utility construction program and other capital requirements (excluding new base load plant and large transmission projects), which are estimated at $900 million over the three-year period spanning 2008-2010, with internally generated funds and externally financed capital. Its internally generated cash after dividends is only expected to provide slightly more than half of its $270-$290 million estimated 2008 capital requirements. In the face of external financing needs, it is anticipated that IPC will seek to maintain capitalization ratios close to the level of March 31, 2008, through periodic additional common equity infusions from its parent company.

As originally articulated in IDA's 2006 Integrated Resource Plan (IRP) regulatory filing, IPC is looking to reduce its reliance on hydro, while also making investments into new transmission assets to help meet load growth and improve its operating performance/reliability. To that end, IPC signed a memorandum of understanding with PacifiCorp on May 18, 2007, under which the companies will pursue the possible development of new high voltage transmission lines from Wyoming across southern Idaho, with target completion set between 2012 and 2014. Another growing component of the IRP is the exploration of potential investments into geothermal power, as evidenced by IPC's negotiations with U.S. Geothermal Inc. IPC named U.S. Geothermal as the successful bidder for 45 MW of geothermal power from the future development of U.S. Geothermal's Raft River geothermal power plant in southeastern Idaho and the initial phase of U.S. Geothermal's Neal Hot Springs project located in southeast Oregon.

A notable shift in the 2006 IRP relates to a decision in April 2008 to not pursue a conventional pulverized coal-fired plant to meet a targeted capacity need in 2013, given concerns about escalating construction costs, ability to obtain requisite permits, and lingering uncertainty related to greenhouse gas laws and regulations. Instead, IPC has issued requests for proposals (RFP) for 250 to 600 megawatts of dispatchable, physically delivered or unit contingent energy to be acquired under power purchase contracts or tolling agreements. We understand that IPC will use a self-build proposal for a combined cycle natural gas combustion turbine as the benchmark to compare proposals against. Proposals are due by October 17, 2008. Meanwhile, IPC plans to officially provide an update on the status of its 2006 IRP to the IPUC and the OPUC in June 2008 and then file a new IRP in June 2009.

Given the magnitude of some of the aforementioned investment considerations, it is possible that IPC's capital budget over 2008 - 2010 could be substantially higher than the $900 million figure cited above. To the extent that IPC moves ahead with investments into renewable and thermal energy resources, as well as transmission line expansion, that provide greater diversification of electric power sources both as to type of generation and geographic locale, Moody's would generally view those investments as a positive for IPC's credit profile, presuming the investments are financed in a conservative manner and receive supportive treatment by the utility's regulators.

CONTINUING NEED FOR FURTHER GENERAL RATE CASE INCREASES AT IPC

Given the forecasted capital expenditure program, in order to maintain a credit metrics profile commensurate with its current rating, it is essential that the utility receive favorable rate case increases from the Idaho and Oregon regulatory authorities in its regulatory filings. IPC's management remains focused on this objective, as evidenced by its notice of intent to file with the IPUC a general rate case on or after June 1, 2008. In addition to the level of rate increase that IPC might seek, key points to focus on in the prospective case will be whether the IPUC fully embraces the forecast test year concept that evolved from work shop discussions with the IPUC staff and other interested parties earlier this year and accepts the concept of including construction work in progress, particularly as it relates to hydro plant re-licensing and other utility investments, as part of the utility rate base.

Separately, we would view any progress toward reducing or eliminating the cost sharing approach under the PCA so that IPC recovers 100% of any power cost under recoveries and development of a mechanism to adjust or replace the current LGAR as credit positive steps (See above for more background on the LGAR solution as it was incorporated into IPC's general rate case settlement approved February 28, 2008).

RENEWED FOCUS ON CORE UTILITY OPERATIONS EMPHASIZES DESIRABILITY OF LOW BUSINESS RISK

Regulatory support is all the more important as the conclusion of divestitures of non-core unregulated businesses previously owned by IDA has left IPC as the principal source of cash flows, with lesser contributions from independent power production at Ida-West Energy and affordable housing investments through IDACORP Financial Services. This renewed focus on core electric utility operations is in line with the overall corporate strategy of a decreased reliance on cash flows from riskier non-utility businesses and has placed greater emphasis on the importance of having a low business risk profile.

Moody's views this back-to-basics focus as being beneficial to IPC, as it helps to ensure that no extraneous capital expenditure demands will detract from the large utility capital program set forth in the IRP. Any deviation from this strategy, such as a foray by the parent company into unregulated corporate acquisitions, would likely necessitate a higher level of scrutiny as to whether IPC's fairly ambitious capital expenditure program will continue to be rolled out without undue hindrance. We also believe that IPC will continue to benefit from IDA's renewed focus on a back-to-basics core energy-related strategy centered on its regulated utility business, insofar as management still may decide to further support IPC's capital program and bolster capitalization and cash flow coverage of debt metrics by periodic issuances of additional common equity.

RECENT PRESSURE ON CASH FLOW METRICS

IPC's CFO Pre-W/C for the 12-months ended March 31, 2008 provided coverage of interest and debt by 2.3x and 6.8%, respectively, reflecting a continuation of weakness evidenced during fiscal 2007 and a marked decline from the 3.3x and 13%, respectively, achieved for fiscal 2006. The decline since the start of 2007 reflects PCA rate differences, less favorable hydro electric operating conditions, and the reduced sales of excess sulfur dioxide emission allowances. Although our prospective view takes into account that key credit metrics, including CFO Pre W/C to debt and interest, may rebound over the next 18 months as the full benefits of recently approved rate increases materialize, the improvement may not be sufficient to re-establish the metrics at levels consistent with what we typically observe for vertically integrated utilities at the Baa1 senior unsecured rating level. Although the sale of sulfur dioxide emission allowances had positive effects (to varying degrees) on earnings and cash flow in 2005 - 2007, we do not factor in similar effects on a prospective basis.

As noted above, IPC's metrics for the 12-months ended March 31, 2008 are pressured relative to the current Baa1 rating and we expect that the company's financial performance will remain subject to the vagaries of water flow conditions. As a result, the adequacy and timeliness of rate relief afforded to IPC by the IPUC in likely future PCA and general rate case proceedings becomes increasingly more important, particularly in light of the higher than historical utility capital expenditures planned for the near term. Our ratings and negative outlook are intended to convey the relative importance that regulatory supportiveness plays in IPC's future credit profile. A key consideration in order for IPC to stabilize its rating outlook and maintain its Baa1 senior unsecured rating will be the extent to which the IPUC is supportive in any future regulatory filings by IPC (i.e. whether they provide supportive rate base treatment of planned utility capital spending and relatively timely recovery of net power supply costs).

After considering Moody's standard adjustments, IPC has been able to maintain its overall debt leverage ratio at 45.6% as of March 31, 2008, which is slightly above the three-year average of 42.6% spanning the period of 2005 to 2007. The calculation of this ratio includes deferred income taxes as part of capitalization. The adjusted debt ratio currently leaves IPC comfortably positioned relative to the range we typically observe for Baa-rated regulated electric utilities. Given the recent slight increase in IPC's debt ratio stemming from higher than historical capital spending, we see the possibility that prospective debt leverage could still creep slightly higher.

Liquidity

On balance, IPC has generally maintained sufficient liquidity, including cash on hand plus its unused capacity under its revolving bank credit facility. In 2007, management negotiated an increase in the amount of IPC's revolver, in order to better cover the prospective liquidity needs of the company as it undertakes a large capital program while drought conditions have resurfaced to pressure cash flow. More recently, IPC also arranged for a $170 million term loan credit agreement as of April 1, 2008, and loans under the agreement are due March 31, 2009. IPC used loans drawn under this facility for a mandatory purchase of $166.1 million of pollution control revenue refunding bonds on April 3, 2008. The company took this voluntary step to effect an interest expense savings through conversion of the bonds from an auction interest rate mode to a weekly interest rate mode. Although IPC is the current holder of the bonds, it expects to remarket the bonds to investors before the March 31, 2009 term loan due date.

The IPC revolving bank credit facility is a $300 million five-year credit agreement, which is principally used to backstop commercial paper. The facility terminates on April 25, 2012. Similar to the amended IDA bank facility, IPC has the right to request an increase in the aggregate principal amount of the IPC facility, in its case to $450 million, and to request one-year extensions of the then existing termination date. At March 31, 2008, there were no borrowings under IPC's facility but $186 million of commercial paper was outstanding. As of May 7, 2008, IPC had $201 million of commercial paper outstanding. It is worth noting that IPC currently has full availability under a $350 million secured medium-term note program, Series H, which it recently put in place. This program provides flexibility for IPC to term out its short-term debt as management has typically done when balances reach levels noted as of May 7, 2008.

Importantly, the IPC bank facility contains less restrictive terms and conditions than historical agreements, as it does not require a representation and warranty that no material adverse change has occurred as a prerequisite to any funding beyond the initial closing date and there are no rating triggers in the agreements that would cause default, acceleration, or puts. The only financial covenant in the facility limits the debt to total capitalization ratio as defined to 65%. At March 31, 2008, the leverage ratio for IPC was 54%. The terms and conditions of the term loan credit agreement essentially mirror the bank revolver.

Beyond the existing commercial paper and term loan balances noted above, IPC has a modest sinking fund payment due within the next year of $1.06 million. Its next scheduled maturity of long term debt is $81 million due December 2009. As noted above, IPC is facing a significant capital program. When capital spending is taken into account along with other expected calls on cash over the next four quarters, we note that IPC will need to access the debt markets and receive equity infusions from its parent to fund its expected negative free cash flow in order to maintain its targeted 50/50 debt/equity mix.

Moody's takes a certain amount of comfort from the relative size of IPC's average outstanding commercial paper balances over the past 12-month period to its credit facility limit amount. For the 12-month period ended March 31, 2008, IPC's commercial paper balances averaged around $116 million, with the $186 million peak balance occurring in March 2008 because of capital expenditures, tax deposits paid to IDA, and reduced operating cash flows. The average balances outstanding were about $34 million during the comparable trailing 12-month period ended March 31, 2007. We anticipate that IPC's commercial paper balances will range between $70 million and $240 million over the next four quarters. The peak amount will likely be dependent upon the timing of IPC's next long-term debt issuance to term out its commercial paper, consistent with management's ongoing practice.

Rating Outlook

IPC's negative rating outlook reflects Moody's concerns about weakness evidenced in the utility's key credit metrics in recent periods, due to the adverse effects that poor hydro conditions and the load growth adjustment rate (LGAR) have had on IPC's earnings and cash flow. Moreover, IPC faces a higher than historical average capital program over the next several years, which will require external financing to fund the expected negative free cash flow. Although recently implemented rate increases during 2008 collectively amount to approximately an additional $120 million of revenue on an annualized basis, these amounts may not be entirely sufficient to restore key credit metrics to levels commensurate with the current ratings.

What Could Change the Rating - Up

The negative outlook due to near term challenges related to a large capital program and the vagaries of operating a large hydroelectric system make an upgrade unlikely in the near term; however, IPC's outlook could be stabilized over the near to medium term through a combination of a return to normalized hydro conditions, stronger regulatory support in future rate proceedings, and improvement in CFO Pre-W/C to interest and debt near 3.5x and 15%, respectively, on a sustainable basis.

What Could Change the Rating - Down

Lower than anticipated earnings and cash flow, perhaps due to the potential continuation of drought conditions over the longer term or unanticipated lack of regulatory support in future PCA and/or general rate case proceedings, such that CFO Pre W/C to interest and adjusted debt stayed below 3.0x and 13%, respectively, for an extended period of time, could result in a negative rating action. Additionally, negative pressure could stem from one or more of the following: significant increases in hydro plant re-licensing costs and/or stringent operational constraints imposed as part of the license renewal process; any unexpected change that compromises the PCA mechanism (i.e., inadequate cost recovery due to the effects of the LGAR as described above); any shift by IDACORP to pursue significant, debt-financed investment in more risky non-regulated businesses that increases demand on IPC cash flow and increases IPC's debt level such that its adjusted debt/adjusted capitalization ratio is inflated to well above 50% on a sustainable basis.

Rating Factors

Idaho Power Company

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-75	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

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My Credit Profile

Table of Contents

Idaho Power Co.

Publication date:	12-Feb-2009
Primary Credit Analyst:	Tony Bettinelli, San Francisco (1) 415-371-5067; antonio_bettinelli@standardandpoors.com

Major Rating Factors

Corporate Credit Rating

BBB/Stable/A-2

Ratings Detail >>

Strengths:

- A strong power cost adjustment (PCA) mechanism that allows 95% of uncollected power costs to be deferred for timely collection;
- A low-cost hydro- and coal-based generating fleet;
- A generally supportive state regulatory regime; and
- The absence of material, unregulated businesses.

Weaknesses:

- High exposure to hydroelectric generation volatility on the Snake River, resulting in unpredictable power supplies and costs, although ultimate recovery is higher due to the company's PCA mechanism;
- Average cash flow to debt persistently at the lower range of current financial risk category; and
- Planning challenges related to generation and transmission needs due to the uncertainty of future growth and recovery.

Rationale

The 'BBB' corporate credit rating on IDACORP is based on the consolidated credit profile of the company, consisting primarily of integrated electric utility Idaho Power Co. (IPC), which carries the same rating, and reflects a 'strong' business profile and 'aggressive' consolidated financial profile. IPC normally provides more than 90% of earnings and most of IDACORP's consolidated cash from operations.

IPC's 'strong' business profile incorporates both its low-cost hydroelectric generation base, which exposes the company to substantial replacement power price risk in the event of low water flows, and a credit-supportive regulatory environment in Idaho. Under normal water conditions, hydrological generation provides about half of total generation needs, necessitating a robust cost recovery mechanism.

The recently authorized improvements to Idaho Power Company's annual power cost adjustment (PCA) mechanism support credit quality and are expected to reduce the under-collection of power costs and reduce cash flow volatility. The most significant credit-supportive modifications to the PCA include a reduction in the sharing mechanism that halves power cost exposure to 5% from 10%, a new forecasted cost methodology that is expected to result in smaller true-up balances, a beneficial change to the punitive load growth add-back adjustment, and the inclusion of third-party transmission costs that have become more onerous in recent years. In exceptionally low water years, deferrals materially weaken cash flows and credit metrics, but we view this primarily as a liquidity matter since 95% of costs above base rates are collected with a carrying charge over 12 months.

The 'aggressive' financial profile is marked by gradual deterioration of cash flow coverage and volatile cash flows. Over time, average credit metrics have deteriorated, but the company has taken steps to stabilize returns and cash flow with new updated base rates and modified power cost mechanisms. Ratios are expected to improve in 2009. As of Sept. 30, 2008, IDACORP's adjusted funds from operations (FFO) coverage of interest and FFO to total debt were 3.1x and 11.1%, respectively, on a 12-month rolling basis. (Credit metrics are adjusted to include the debt equivalent of leases, purchased power obligations, and postretirement benefit obligations.) Cash flow-based coverage ratios have improved slightly but steadily over the past two quarters, based on the impact of multiple rate increases over the past 12 months. While leverage remains reasonable for the rating, with an adjusted debt-to-total-capitalization ratio at 57.3% as of Sept. 30, 2008, it has increased slightly due to a higher proportion of debt being used to fund capital expenditures. Management indicated in the August earnings call that additional equity may be used to maintain a balanced capital structure, however.

Short-term credit factors
IDACORP's 'A-2' short-term rating reflects its adequate liquidity. Liquidity is provided by a $100 million, five-year credit agreement at IDACORP and a $300 million, five-year credit facility at IPC, primarily used for deferred power costs. At Nov. 5, 2008, $146 million of commercial paper (CP) backed by the facility was outstanding at IPC and $58 million of CP and draws were outstanding at IDACORP. Both facilities terminate on April 25, 2012. Cash flows are volatile and highly dependant on hydrological conditions. Twelve-month rolling cash flows from operations as of Sept. 30, 2008, totaled $149 million, versus only $39.8 million a year earlier. Cash and cash equivalents as of Sept. 30, 2008, were $57.7 million.

Debt maturities are moderate at $87 million in 2009, and $4 million in 2010. A temporary $170 million 12-month term loan was recently renewed, as the company works to restructure some re-purchased tax-exempt debt.

Planned capital expenditures in 2008 had been reduced to $235 million-$250 million from $280 million-$300 million and further refinement would not be surprising, as the customer growth outlook has been reduced. Slower growth will reduce borrowing needs, although generated cash, debt, and equity may be needed as capital sources to maintain a balanced capital structure.

Outlook

The stable outlook reflects a requisite level of regulatory support and expected long-term financial metrics that are adequate for the ratings -- above current levels. A downward rating action may occur if the company does not carefully manage costs and investments to ensure full recovery, especially in light of a weakening economy. Improvement in credit ratings, although unlikely in the near term, would require significantly stronger financial metrics over a longer-term horizon, in addition to solid regulatory support.

Table 1 | Download Table

IDACORP Inc. -- Peer Comparison*

Industry Sector: Electric

	IDACORP Inc.	Avista Corp.	Puget Energy Inc.	Portland General Electric Co.	NorthWestern Corp.
Rating as of Feb. 5, 2009	**BBB/Stable/A-2**	**BBB-/Stable/A-3**	**BB+/Stable/--**	**BBB+/Negative/A-2**	**BBB/Stable/--**
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	882.8	1,427.9	2,899.7	1,569.7	1,159.0

Exhibit No. 5
Case No. IPC-E-09-03
L. Smith, IPC
Page 9 of 15

Net income from cont. oper.	89.4	52.3	166.1	93.3	50.7
Funds from operations (FFO)	159.2	187.4	442.5	281.2	176.9
Capital expenditures	232.8	194.5	726.5	359.6	122.7
Debt	1,416.1	1,349.9	3,343.9	1,390.0	958.1
Equity	1,099.7	873.6	2,298.5	1,217.5	767.8
Adjusted ratios					
Oper. income (bef. D&A)/ revenues (%)	30.7	18.7	26.9	27.3	20.1
EBIT interest coverage (x)	2.3	1.8	2.0	2.3	2.2
EBITDA interest coverage (x)	3.6	2.6	3.4	4.3	3.1
Return on capital (%)	5.9	6.8	7.5	8.4	8.4
FFO/debt (%)	11.2	13.9	13.2	20.2	18.5
Debt/EBITDA (x)	5.3	5.1	4.3	3.2	4.3

*Fully adjusted (including postretirement obligations).

Table 2 | Download Table

IDACORP Inc. -- Financial Summary*

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2007	2006	2005	2004	2003
Rating history	BBB+/Negative/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2
(Mil. $)					
Revenues	879.4	926.3	842.9	827.9	823.0
Net income from continuing operations	82.3	100.1	85.7	80.8	46.5
Funds from operations (FFO)	119.2	189.5	168.9	185.9	238.5

Capital expenditures	279.8	225.8	192.9	196.8	153.6
Cash and short-term investments	8.0	9.9	52.4	23.4	75.1
Debt	1,545.8	1,355.5	1,347.0	1,175.7	1,179.0
Preferred stock	0.0	0.0	0.0	0.0	52.4
Equity	1,207.3	1,124.2	967.5	956.4	870.9
Debt and equity	2,753.1	2,479.7	2,314.5	2,132.1	2,049.9
Adjusted ratios					
EBIT interest coverage (x)	2.1	2.5	2.4	1.9	1.5
FFO int. cov. (x)	2.4	3.5	3.3	3.6	4.7
FFO/debt (%)	7.7	14.0	12.5	15.8	20.2
Discretionary cash flow/ debt (%)	(14.7)	(6.6)	(4.9)	(4.0)	7.3
Net cash flow/capex (%)	23.7	61.2	61.2	71.2	113.1
Debt/debt and equity (%)	56.1	54.7	58.2	55.1	57.5
Return on common equity (%)	5.9	8.4	7.6	7.9	5.3
Common dividend payout ratio (un-adj.) (%)	64.4	51.2	59.1	56.7	139.1

*Fully adjusted (including postretirement obligations).

Table 3 | Download Table

IDACORP Inc.--Quarterly Data*

Industry Sector: Electric

	September 2008	June 2008	March 2008	December 2007	September 2007
(Mil. $)					
Revenues	299.7	230.2	213.4	197.4	261.5

Exhibit No. 5
Case No. IPC-E-09-03
L. Smith, IPC
Page 11 of 15

Net income from continuing operations	51.7	17.5	21.7	10.3	28.9
Funds from operations (FFO)	56.7	53.1	59.5	19.8	37.4
Capital expenditures	49.1	70.5	52.9	78.2	82.1
Cash and short-term investments	57.7	8.9	7.4	8.0	16.7
Debt	1,705.4	1,651.2	1,601.1	1,545.8	1,501.2
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	1,270.7	1,224.6	1,217.5	1,207.3	1,208.1
Debt and equity	2,976.1	2,875.8	2,818.6	2,753.1	2,709.3
Adjusted ratios					
EBIT interest coverage (x)	2.3	2.0	2.1	2.1	2.2
FFO int. cov. (x)	3.1	3.0	2.9	2.8	2.9
FFO/debt (%)	11.1	10.3	9.7	9.5	10.0
Discretionary cash flow/debt (%)	(7.2)	(11.8)	(12.1)	(12.9)	(15.2)
Net cash flow/capex (%)	54.0	41.3	36.0	33.5	37.9
Debt/debt and equity (%)	57.3	57.4	56.8	56.1	55.4
Return on common equity (%)	6.6	5.2	5.6	5.9	7.0
Common dividend payout ratio (un-adj.) (%)	53.2	68.4	67.2	64.4	57.4

Table 4 | Download Table

Reconciliation Of IDACORP Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

--Fiscal year ended Dec. 31, 2007--

IDACORP Inc. reported amounts	Debt	Operating income (before D&A)	Operating income (before D&A)	Operating income (after D&A)	Interest expense	Cash flow from operations	Cash flow from operations	Capital expenditures
Reported	1,354.8	252.4	252.4	149.3	63.3	80.6	80.6	287.8
Standard & Poor's adjustments								
Operating leases	15.3	3.8	1.0	1.0	1.0	2.8	2.8	--
Postretirement benefit obligations	50.3	(2.5)	(2.5)	(2.5)	--	(4.3)	(4.3)	--
Capitalized interest	--	--	--	--	8	(8)	(8)	(8)
Share-based compensation expense	--	--	2.7	--	--	--	--	--
Power purchase agreements	115.9	10.3	10.3	6.6	6.6	3.7	3.7	--

Asset retirement obligations	9.4	0.7	0.7	0.7	0.7	(0.7)	(0.7)	--
Reclassification of nonoperating income (expenses)	--	--	--	10	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	13.2	--
Other	--	--	--	--	--	31.9	31.9	--
Total adjustments	191	12.3	12.2	15.8	16.3	25.4	38.6	(8)
Standard & Poor's adjusted amounts								
	Debt	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	1,545.80	264.7	264.6	165.1	79.6	106	119.2	279.8

*IDACORP Inc. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of 12-Feb-2009)*	
Idaho Power Co.	
Corporate Credit Rating	BBB/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured (11 Issues)	A-
Senior Secured (4 Issues)	A/Negative
Senior Unsecured (2 Issues)	BBB/A-2
Corporate Credit Ratings History	
31-Jan-2008	BBB/Stable/A-2
27-Mar-2006	BBB+/Negative/A-2
29-Nov-2004	BBB+/Stable/A-2
15-Jun-2004	A-/Watch Neg/A-2
Related Entities	
IDACORP Inc.	
Issuer Credit Rating	BBB/Stable/A-2
Commercial Paper	
Local Currency	A-2

***Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.**

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My Credit Profile
IDACORP Inc., ID - 'BBB/Stable/A-2'

Table of Contents

Summary: Idaho Power Co.

Publication date: 12-Feb-2009
Primary Credit Analyst: Tony Bettinelli, San Francisco (1) 415-371-5067; antonio_bettinelli@standardandpoors.com

Rationale

The 'BBB' corporate credit rating on IDACORP is based on the consolidated credit profile of the company, consisting primarily of integrated electric utility Idaho Power Co. (IPC), which carries the same rating, and reflects a 'strong' business profile and 'aggressive' consolidated financial profile. IPC normally provides more than 90% of earnings and most of IDACORP's consolidated cash from operations.

IPC's 'strong' business profile incorporates both its low-cost hydroelectric generation base, which exposes the company to substantial replacement power price risk in the event of low water flows, and a credit-supportive regulatory environment in Idaho. Under normal water conditions, hydrological generation provides about half of total generation needs, necessitating a robust cost recovery mechanism.

The recently authorized improvements to Idaho Power Company's annual power cost adjustment (PCA) mechanism support credit quality and are expected to reduce the under-collection of power costs and reduce cash flow volatility. The most significant credit-supportive modifications to the PCA include a reduction in the sharing mechanism that halves power cost exposure to 5% from 10%, a new forecasted cost methodology that is expected to result in smaller true-up balances, a beneficial change to the punitive load growth add-back adjustment, and the inclusion of third-party transmission costs that have become more onerous in recent years. In exceptionally low water years, deferrals materially weaken cash flows and credit metrics, but we view this primarily as a liquidity matter since 95% of costs above base rates are collected with a carrying charge over 12 months.

The 'aggressive' financial profile is marked by gradual deterioration of cash flow coverage and volatile cash flows. Over time, average credit metrics have deteriorated, but the company has taken steps to stabilize returns and cash flow with new updated base rates and modified power cost mechanisms. Ratios are expected to improve in 2009. As of Sept. 30, 2008, IDACORP's adjusted funds from operations (FFO) coverage of interest and FFO to total debt were 3.1x and 11.1%, respectively, on a 12-month rolling basis. (Credit metrics are adjusted to include the debt equivalent of leases, purchased power obligations, and postretirement benefit obligations.) Cash flow-based coverage ratios have improved slightly but steadily over the past two quarters, based on the impact of multiple rate increases over the past 12 months. While leverage remains reasonable for the rating, with an adjusted debt-to-total-capitalization ratio at 57.3% as of Sept. 30, 2008, it has increased slightly due to a higher proportion of debt being used to fund capital expenditures. Management indicated in the August earnings call that additional equity may be used to maintain a balanced capital structure, however.

Short-term credit factors

IDACORP's 'A-2' short-term rating reflects its adequate liquidity. Liquidity is provided by a $100 million, five-year credit agreement at IDACORP and a $300 million, five-year credit facility at IPC, primarily used for deferred power costs. At Nov. 5, 2008, $146 million of commercial paper (CP) backed by the facility was outstanding at IPC and $58 million of CP and draws were outstanding at IDACORP. Both facilities terminate on April 25, 2012. Cash flows are volatile and highly dependant on hydrological conditions. Twelve-month rolling cash flows from operations as of Sept. 30, 2008, totaled $149 million, versus only $39.8 million a year earlier. Cash and cash equivalents as of Sept. 30, 2008, were $57.7 million.

Debt maturities are moderate at $87 million in 2009, and $4 million in 2010. A temporary $170 million 12-month term loan was recently renewed, as the company works to restructure some re-purchased tax-exempt debt.

Planned capital expenditures in 2008 had been reduced to $235 million-$250 million from $280 million-$300 million and further refinement would not be surprising, as the customer growth outlook has been reduced. Slower growth will reduce borrowing needs, although generated cash, debt, and equity may be needed as capital sources to maintain a balanced capital structure.

Outlook

The stable outlook reflects a requisite level of regulatory support and expected long-term financial metrics that are adequate for the ratings -- above current levels. A downward rating action may occur if the company does not carefully manage costs and investments to ensure full recovery, especially in light of a weakening economy. Improvement in credit ratings, although unlikely in the near term, would require significantly stronger financial metrics over a longer-term horizon, in addition to solid regulatory support.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-03

IDAHO POWER COMPANY

SMITH, DI
TESTIMONY

EXHIBIT NO. 6

EDISON ELECTRIC INSTITUTE

WHITE PAPER

UNDERSTANDING DEBT IMPUTATION ISSUES

BY

THE BRATTLE GROUP

FOR

THE EDISON ELECTRIC INSTITUTE

The Brattle Group 44 Brattle Street Cambridge, Massachusetts 02138 617.864.7900

Final Draft: 3-Jun-08

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The purpose of this white paper is to explore the issue of **debt imputation**. It is written for EEI members and regulatory staff, to understand the issue, and review options for addressing it in the rate making process.

Section I, *Introduction*, defines "imputed debt" as a measure of the financial risk shifted to a utility when it enters into a purchase power agreement ("PPA"). Use of PPAs can undermine the utility's credit worthiness, if no financial adjustment is made to its capital structure.

Section II, *Wholesale Market Developments Increase the Importance of Imputed Debt*, explains that the use of PPAs was spurred by PURPA and the Energy Policy Act of 1992. With a few exceptions, the original concept of a fully competitive wholesale market (i.e., in which all generation is owned by independent power producers - IPP), has given way to a hybrid wholesale market in which generation is owned both by regulated utilities and IPPs.

Section III, *How is Imputed Debt Calculated?*, reviews Standard & Poor's (S&P) updated methodology for calculating the debt equivalence of PPAs and imputing it onto a utility's balance sheet and income statement for the purpose of assessing credit worthiness. The debt equivalence value is calculated as the present value of the fixed (capacity) portion of annual payment, discounted at the utility's average cost of debt, and multiplied by a risk factor. The risk factor is intended to reflect the probability that PPA costs will be fully recovered in rates and varies depending on state-specific legislative and/or regulatory policy. Greater certainty of recovery is reflected in a lower risk factor which results in a smaller amount of equivalent debt per contract. Imputed interest expense, calculated as the equivalent debt times the embedded debt cost, is added to the utility's interest expense. An annual amount of depreciation is also estimated as the difference between the capacity payment and the imputed interest for the year. Imputed debt, imputed interest expense and imputed depreciation affect the three key ratios S&P uses to assess credit worthiness (i.e., debt/total capital, funds from operations ("FFO")/average total debt, and FFO/interest expense).

Section IV, *Is Debt Equivalence a Real Problem?*, demonstrates that imputed debt is a problem whose potential severity should be of concern to regulatory authorities. Like debt, PPAs increase the utility's financial risk by obligating future cash flow. Fixed payment obligations, like interest payments and the payments for a PPA, reduce financial flexibility and increase the probability that the utility will default on its obligations. For proof that PPAs transfer risk to utilities, we need only examine the reciprocal effect that PPAs have on the suppliers (the counterparties to PPAs). According to S&P, PPAs reduce supplier risk. This can only be true if supplier risk is being transferred to the utility and its customers via the terms of the PPA. For policy makers, debt equivalence should be of concern because it can affect credit ratings by either impeding upgrades and/or triggering down grades. Weaker credit ratings, in turn, can increase borrowing costs and/or restrict borrowing capacity, both of which harm rate payers.

Section V, *How Big A Problem is Imputed Debt?*, shows that for utilities whose credit ratings are marginally investment-grade, imputed debt can be a big problem. For such utilities, imputation of PPA-related debt equivalence could push their credit below investment-grade status. For the seven electric utilities whose data S&P publishes, average debt to equity was 58% before imputation and 63% after. Even for utilities with a business risk profile of "Excellent" or "Strong", a 58% ratio corresponds to an "aggressive" financial risk indicator and a low BBB to high BBB- credit rating, while a 63% ratio corresponds to a "highly leveraged" financial risk indicator and a BB to BB- rating.

Section VI, *Mitigation of the Impact of Imputed Debt*, describes three options for addressing debt imputation. These are summarized in Table ES-1.

Table ES-1: Options for Addressing Imputed Debt	
Method	**Considerations**
1. INCREASED EQUITY - Increase equity, decrease debt to restore pre-PPA capital structure	• Mitigates PPA financial risk • Does not completely restore FFO/interest, FFO/debt ratios • Expensive to use for each PPA • Incurs cost to issue new equity
2. INCREASED ROE - Increase allowed ROE so that pre-PPA ATWACC = post-PPA ATWACC	• Compensates shareholders for increased risk • Does not fully restore any ratios • Not sufficient for utilities with low credit ratings
3. RATIO RESTORATION - Impute new equity sufficient to restore selected ratio to pre-PPA level, collect this via an adder to the PPA payment	• Compensates shareholders for increased risk • Mitigates financial risk • Can be applied for each PPA • Helps utilities with low credit better than methods # 1 and 2 • More expensive than methods # 1 and 2 • Requires choice of which ratio to restore

Section VII, *Conclusions*, suggests five overall conclusions for policy makers, as follows: (1) Long-term purchase power agreements (PPA) transfer financial risk from the seller to the buyer; (2) Policy makers should be particularly sensitive to PPA-related risk transfer in situations where the utility's credit rating is minimally investment-grade; (3) Regulatory policies which provide assurance of PPA cost recovery can effectively mitigate the impact of imputed debt on the credit rating of purchasing utilities; (4) There is no perfect solution to the problem of PPA-related risk transfer and imputed debt; and (5) In competitive procurement situations, it is important that imputed debt be addressed in a competitively-neutral way.

Appendix A, *Treatment of Imputed Debt in Certain States*, surveys recent precedent involving PPAs and imputed debt. Recent state decisions are summarized in Table ES-2.

Table ES-2: Recent State Precedent		
CA	Has retreated from an earlier policy that allowed IPP bids to be adjusted to account for risk transfer. Now considers debt equivalence after-the-fact in the utilities' costs of capital.	*Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's Long-Term Procurement Plans,* Decision 07-12-052, December 20, 2007.
DE	Allowed Delmarva to assign a cost adder to bid prices based on imputed equity equal to 30% of the NPV of capacity payments, and a portion of the energy payment if the Company concludes that energy payments will be imputed as debt by rating agencies.	Order No. 7081, 11/21/06
FL	Allowed FPL to increase its equity thickness to offset PPA-related imputed debt. Also requires utilities to include the cost of incremental equity in comparing PPAs to other resource options.	*Order Approving Stipulation and Settlement*, Docket No. 990067-EI, Order No. PSC-99-0519-AS-EI, 3/17/99. See also 70 F.A.C. Rule 25-22.081, paragraph 7.71 Order No. PSC-99-1713-TRF-EG, Docket No. 990249-ET, 9/2/99. (??)
NV	Promulgated rules that allow PPA adders tied to the cost of offsetting equity. To date, no adders have been approved.	NRS 704.7821(7) (b), issued pursuant to Assembly Bill No. 3, passed June 2005.
NM	Denied a PPA adder tied to the cost of offsetting equity. Apparently, the commission found insufficient evidence that the utility's credit rating would fall below investment-grade as the result of imputation.	*Final Order on Exceptions*, Case No. 06-00340-UT, 12/18/06
WI	Allowed WI Public Service Corp. to add new equity to offset imputed debt from long term PPAs and operating leases.	*Final Decision*, 6690-UR-118, 1/15/08

I. INTRODUCTION

With the growth and importance of competitive wholesale markets, many regulated electric utilities enter into long-term purchased power contracts ("PPAs") to meet the power supply needs of their customers in a least cost and reliable manner.[1] Regulated utilities have traditionally passed (or attempted to pass) all purchased power costs through to ratepayers on a dollar-for-dollar basis without any compensation accruing to the utility. However, full recovery is contingent on approval by the utility's regulatory body, including any regulatory lag.[2] The financial community and the rating agencies recognize that there are different regulatory risks involved in the different state regulatory approaches to the recovery of purchased power (and fuel) costs.[3] This means that signing a long-term PPA increases the financial risk of the purchasing utility commensurate with the size and length of the fixed-cost obligations in the contract. The amount of financial risk also depends on the likelihood of full recovery of the costs of the contract, which in turn depends on the supportiveness of the regulatory and legislative climate.

The financial risk inherent in signing a long-term PPA is measured by the credit rating agencies and is known as "imputed debt" or "debt equivalence".[4] (This paper will use the term "imputed debt" for ease

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[1] The authors are aware of the current controversies about the functioning of the U.S. wholesale power markets but believe that the issues discussed here will continue to be important in whichever direction state and national competitive policy moves.

[2] In this context, regulatory lag refers to the delay between the time costs are incurred and the time those costs are recovered in rates. If there is a substantial delay in recovery, the utility would not be fully compensated for the cost of the PPAs unless the PPA balances receive a carrying cost. In other words, the utility would lose the time value of money.

[3] For example, S&P's, "Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets – U.S. Utilities to Watch", Report, March 22, 2006 and S&P's, "Request For Comments: Imputing Debt To Purchased Power Obligations," November 1, 2006.

[4] Credit rating agencies have generally treated long-term PPA contracts differently from short-term power contracts. In the past, credit rating agencies did not believe that short-term contracts (in particular those signed in retail access states for Provider of Last Resort ("POLR") service, which are generally three-month to three-year contracts) and face

of exposition). One credit rating agency, Standard & Poor's (S&P), has clearly stated its view for many years that long-term PPAs impose financial risk on the utility and has developed and publicized a standard procedure for calculating imputed debt and its impact on the financial ratios used to measure a utility's creditworthiness.[5] If nothing were done, the imputed debt resulting from a large portfolio of PPAs may lead to a credit rating downgrade. In addition, the imputed debt resulting from a large portfolio of PPAs could lead to a credit downgrade. In addition, the weakened credit ratings (i.e., increased financial risk) would increase the purchaser's cost of equity and debt capital assessed by financial markets.

In light of the continuing importance of long-term PPAs, this paper reviews and illustrates the financial risk of concern to the credit rating agencies. In particular, the paper addresses the issue of whether the financial risk from long-term PPAs is a real concern, and if so, how big a problem it is likely to be. If the problem is real and large enough to be of concern, what can regulators do to mitigate its effects? Below, the paper discusses several alternative ways to mitigate the adverse effects of imputed debt on the purchasing utility. The goal of any mitigation effort should be to treat shareholders and rate payers fairly, but mitigation will also benefit ratepayers and shareholders by neutralizing the negative effects from PPAs, including the weakening of the company's credit metrics and the increased cost of capital.

The rest of this paper is organized as follows: *Section II* briefly describes the development of the wholesale generation market and the coming generation "build out". *Section III* describes the credit rating agencies' views and illustrates the calculation of imputed debt based upon the method published

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rebid periodically to keep prices closer to the spot market), carried the same negative financial impact as a long-term PPAs. However, S&P recently announced that it is will impute debt from most such "evergreen" contracts going forward. See, *Imputed Debt Calculation for U.S. Utilities' Power Purchase Agreements*, S&P RatingsDirect, March 30, 2007. S&P excludes PPAs in which the utility merely acts as a conduit for delivery of power. See *Standard & Poor's Encyclopedia Of Analytical Adjustments for Corporate Entities*, July 9, 2007 p. 24.

[5] Periodically S&P has revised its procedures for calculating imputed debt. This paper reflects S&P's current policy.

Exhibit No. 6
Case No. IPC-E-09-03
L. Smith, IPC
Page 8 of 48

by S&P and its effect on a utility's credit ratios. *Section IV* addresses the issue of whether imputed debt is a problem that should be of concern to regulators, and *Section V* illustrates how large the problem could be given the increase in PPA type contracts. *Section VI* describes the approaches that a regulatory agency might adopt to mitigate the effects of imputed debt on the financial ratios of a utility should it chose to do so, and *Section VII* provides concluding remarks. *Appendix A* contains a discussion of the current treatment of imputed debt in the states of California, Delaware, Florida, Nevada, New Mexico and Wisconsin. The appendix reports how these states have chosen to deal with the issue at this time.

II. WHOLESALE MARKET DEVELOPMENTS INCREASE THE IMPORTANCE OF IMPUTED DEBT

Long-term wholesale power purchase contracts have been a source of supply for regulated utilities for many years, but before the 1980's, most utilities met their obligation to serve through their own generation resources. Growth in long-term purchased power contracts was spurred by PURPA[6] policies in the 1980s and became wide reaching after the Energy Policy Act of 1992 began the process of providing open access to the FERC-regulated transmission grid. The Energy Policy Act also created the category of exempt wholesale generator ("EWG") which is a generator that is permitted to sell electricity only in the wholesale market.[7] Long-term contracting for supply from EWGs by regulated utilities became a standard part of wholesale power markets. In the early 1990s, S&P as well as some financial analysts recognized that there is a risk transfer from the seller to the buyer inherent in long-term purchased power contracts resulting from PURPA and the growth of the role of EWGs in the wholesale

[6] The Public Utility Regulatory Policies Act of 1978

[7] See U.S. Code, Title 15, Chapter 2C, Section 79z - 5a.

power market.[8] Over the last twenty years, independent power producers ("IPPs") have become major builders of power plants, owners of existing generation resources, and potential low-cost developers of new resources. Many states now require that a utility proposing to build its own plant demonstrate that the proposed plant is in the ratepayers' interest by being lower in expected future revenue requirements than competitive bids for comparable supply from IPPs.

The original 1990's concept of a fully competitive wholesale power market envisioned that eventually all electric generation plants (outside the public power sector) would be owned by independent power producers (some of whom would possibly be affiliated with regulated distribution utilities), selling under long-term contracts, short-term contracts, or in the spot market.[9] A corollary of that vision was that all new electric generation assets would be built with private investment in the form of independent merchant plants or plants with contracts from retail marketers or large customers. There would be little or no role for plants built under cost-of-service regulation.

In fact, the history of the development of a competitive wholesale market has not been smooth and includes the California energy crisis (with eight FERC Settlements and $3-5 billion in refunds) and the heightened concerns about market power abuse and the need for its mitigation. Moreover, there has not been the full development of a competitive retail market for all customers in most retail access states

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[8] S&P first published its criteria for evaluating long-term PPAs in 1990, updated them in 1993, and most recently in early 2007. See " 'Buy Versus Build': Debt Aspects of Purchased-Power Agreements," *Utilities & Perspectives*, May 12, 2003, p. 2. See also "Imputed Debt Calculation for U.S. Utilities' Power Purchase Agreements," *S&P RatingsDirect*, March 30, 2007, "Purchased Power - Hidden Cost or Benefits?", *The Electricity Journal*, September 1994, pp. 74-83, by A. L. Kolbe, S. Johnson, J.P. Pfeifenberger and D. M. Weinstein, and "A Simplified Procedure for Costing the Risks of Purchased Power Contracts," *The Electricity Journal*, April 1997, pp. 70-75 by William B. Tye and Marvin A. Hawthorne.

[9] "Keeping up with retail access? Developments in U.S. Restructuring for Regulated Retail Service," *The Energy Journal*, December 2004, by J. Pfeifenberger, A. Schumacher and J. Wharton. The authors note that states in the U.S. can be divided into three groups: the retail access states share this vision, the traditional regulation states do not share this vision, and the transition states which started toward retail competition and stopped (e.g., California) or did partial retail access for only large customers (Nevada and Oregon). The third group and possibly the second procure long-term resources for their portfolios using PPAs or both PPAs and utility-owned generation plants.

during the transition periods. Texas and some other states continue to pursue the original vision of wholesale competition, generation investment by independent producers, and price rationing of scarce supplies should a shortage come to pass. However, policy makers in many states have questioned the efficacy of actual, or potential, shortage premiums in spot prices as effective and reasonable long-range signals for new generation investment and resource adequacy. The majority of states never adopted retail access and some of those that did are reviewing the policy in light of recent developments.[10]

Fitch Ratings ("Fitch") has come to be skeptical about the amount of new generation that will be built by IPPs without long-term contracts with regulated utilities. In a 2005 report, Fitch concluded that:[11]

> . . . states are unlikely to test the fourth alternative of competitive [wholesale] markets, allowing the competitive market to work and waiting to see the result. . . . Evidently the public is unwilling to accept the volatility associated with a purely competitive wholesale market. It would appear that competition is politically acceptable when it lowers prices, but not when it raises them. [Emphasis added]

A "hybrid wholesale market" model has now emerged where, over the long term, policy makers will encourage a balance of new generation plants that are owned and operated (and sometimes built) by regulated utilities and generation plants that are owned and operated by independent power producers with or without long-term contracts. California is prominent in pursuing the hybrid market structure.[12] Long-term contracts will continue to play a major role in the hybrid wholesale markets, so imputed debt will continue to be an important issue in assessing utility financial strength.[13]

[10] See discussion of Delaware in the Appendix for a development in the direction.

[11] Fitch Ratings, "Stimulating Generation Additions in Deregulated States," *Corporate Finance*, Nov. 4, 2005.

[12] See CPUC Decision 06-07-029, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, July 20, 2006.

[13] As is reflected in Appendix A, utilities' dependence on long-term PPA's is also increasing because of the impact of renewable resource portfolio standards.

III. HOW IS IMPUTED DEBT CALCULATED?

Imputed debt, or debt equivalence, is a term used by credit rating agencies and financial analysts to describe and quantify the financial risk inherent in the fixed financial obligation resulting from signing long-term contracts, such as purchased power agreements or operating leases. Under current FASB standards, these obligations are not reported on the company's balance sheet although the accompanying notes do disclose these arrangements.[14] However, these contracts have debt-like characteristics because they commit the utility to pay periodically a fixed amount to an outside party. Because these obligations have features similar to debt, they are treated as such to some degree by the credit rating agencies. S&P has developed and publicized a standard procedure for calculating the amount of imputed debt resulting from signing a long-term PPA contract and for determining its impact on a utility's creditworthiness. Other credit rating agencies, such as Moody's or Fitch Ratings, have been less forthcoming in how they evaluate the effect of a long-term PPA contract on a utility's credit rating. Consequently, this paper relies primarily on S&P's published materials to illustrate the calculation of imputed debt and its impact on a utility's financial ratios.[15]

Another way to view the risk characteristics of imputed debt is to recognize that building and operating an electric generating plant entails substantial risk. This is true whether the plant is built by a utility or by an IPP. Frequently, the only way an IPP developer can secure financing to construct a power plant is by first contracting with a credit-worthy regulated utility. The fixed, contractual PPA payments serve as the basis for the developer to obtain financing at reasonable rates. If built by a utility, the debt and equity used to finance construction of the plant would appear on the regulatory books of the utility, but not if the same financial commitment is made through a PPA. The concept of imputed debt simply

[14] Recent financial accounting standards appear to be moving in the direction of greater scrutiny of PPA contracts that has the potential for some contracts to be classified as capital leases which would require them to be reported on the utility's balance sheet.

recognizes that there is a risk transfer from the developer to the regulated utility inherent in the commitment to make the PPA payments and attempts to recognize the underlying economics of the transaction. Without recognition of the increased financial risk from the PPA, signing a PPA would have the illogical result of seeming to make the risk of investing in electric generating plants disappear. Moreover, all else equal, electric power plants proposed by IPPs may be incorrectly chosen as least expensive in a head-to-head competition with a regulated utility if the risk transfer were not recognized.[16] Thus, the calculation of imputed debt recognizes that the mechanism of a PPA does not eliminate risk, but merely transfers the risk to the utility and its ratepayers. The division of the risk transfer between the utility and its ratepayers depends upon the regulatory mechanisms in place for recovery of the costs of the PPA as measured by S&P using its so-called "risk factor" which is described below.

A. STANDARD & POOR'S IMPUTED DEBT METHODOLOGY

In the electric industry, S&P imputes debt for purchased power contracts, operating leases, and the unfunded portion of post-retirement obligations. S&P is specific about its calculations. To understand how imputed debt is assessed, it is helpful to review S&P's explicit approach as it has been defined in publications over the years. The calculation of imputed debt for PPAs parallels the treatment of operating leases, which is discussed first.

[15] Below, the other two credit rating agencies, Moody's and Fitch, are briefly discussed in comparison on some points.

[16] There is not universal agreement on this point. For example, The Electric Power Supply Association ("EPSA") believes that acknowledging the risk of imputed debt risks tilting the competition between IPPs and regulated utilities in favor of utilities if construction risk and other risks accepted by IPPs are not recognized. See for example, "Impacts of Credit Requirements, Cost of Capital and Debt Equivalency Issues on Power Supply Acquisition (Remarks by EPSA President and CEO John E. Shelk at the *Western Power Supply Forum* - May 9, 2006). The authors of this paper believe that an accurate judgment in the build-versus-buy decision requires consideration of *all* of the risks including construction risk and imputed debt.

For operating leases,[17] S&P calculates the present value of future minimum lease payments using the utility's average embedded interest rate. The resulting amount is added to the utility's reported long-term debt for purposes of calculating the utility's financial ratios.[18] In addition, an implicit (or imputed) interest expense is calculated as the average net present value of the contract payments multiplied times the utility's average interest rate. This implicit interest is added to the reported interest expense for the purpose of calculating ratios. An imputed depreciation amount is also determined as the average of the year-one minimum lease payment in the current and previous year minus the implicit interest expense.[19] This amount is added to the reported depreciation expense.[20]

Fitch Ratings also calculates adjusted ratios for operating leases. Fitch uses one of two methods to value off-balance sheet lease obligations.[21] One method relies on a multiple of the minimum annual lease obligation (typically 8 *times* the annual obligation). A second method calculates the present value ("PV") of non-cancellable future lease obligations. When enough information is available to calculate both estimates of the lease obligations, Fitch Ratings takes both into account. Fitch Ratings uses the adjusted figures in calculating leverage and coverage ratios using the adjusted debt amount and

[17] Under current accounting standards, capital leases are recognized on a company's balance sheet while operating leases are not. A lease is classified as a capital lease if it satisfies one of four criteria: (1) ownership of the asset is transferred to the lessee, (2) the lease contains a bargain purchase option - - i.e., the lessee can purchase the asset at below fair market value, (3) the lease term is equal to 75% or more of the asset's economic life, or (4) the present value of the minimum lease payments equals or exceeds 90% of the fair value of the leased property. Leases that do not meet any of these criteria are operating leases.

[18] This amount is also added to assets, to reflect the implicit value the utility has from using the asset, when calculating ratios that involve assets.

[19] To ensure that expenses properly reflect the imputed debt amount rather than the reported amount, the average of the current and previous year's minimum lease payment minus the implicit interest expense is added to the reported expenses. This is simply to avoid double-counting of any amount.

[20] Moody's Investor Service appears to be using a similar approach. S&P's and Moody's use analytical models to convert leases using present value of minimum lease payments. Moody's capitalizes full notional value of 'essential' or 'core' assets, 1st Annual ELA/SEC Meeting, September 8, 2005.

[21] Fitch Ratings, *Corporate Finance*, "Operating Leases: Updated Implications for Lessees," *Credit*, December 20, 2006.

including the total lease expense in the interest expense.[22] Fitch states that the adjustment is significant for about half the entities they follow. This paper focuses on imputed debt arising from PPAs; therefore, the treatment of operating leases and unfunded pension liabilities is not discussed further.

S&P's method for calculating imputed debt begins by determining the PV of the fixed payment (capacity) portion of the PPAs, using the utility's average embedded cost of debt as the discount rate. "If capacity payments are not specified, S&P will use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied times the number of kilowatts under contract."[23]

S&P next determines a so-called "risk-factor" which is a company-specific measure of the likelihood of full recovery of the costs of the PPA. S&P determines the risk factor based upon characteristics of the company and its regulatory environment. Risk factors vary between 0 and 100 percent, but they are typically in the range of 25 to 50 percent. For rate-regulated utilities, the risk factor depends primarily on the regulatory environment and especially on the mechanism used to recover capacity costs. As a benchmark, S&P states the risk factor "will generally be 25% for capacity payments that are recovered through fuel adjustment clauses and 50% for capacity payments that are recovered in base rates."[24,25] Unregulated energy companies that enter into a tolling arrangement are generally assigned a risk factor

[22] Fitch Ratings discusses a third method which is primarily applied to entities in bankruptcy or reorganizing. In this case Fitch Ratings looks at the liquidation value.

[23] See "Standard & Poor's Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements," S&P *Commentary Report*, May 7, 2007, p. 5.

[24] "Request for Comments: Imputing Debt to Purchased Power Obligations," Standard & Poor's, November 1, 2006.

[25] **Error! Main Document Only.**S&P believes that vertically integrated, regulated electric utilities with a fuel adjustment clause have moderate risk and recently adjusted the risk factor for such utilities downward to 25% (from 30%). In jurisdictions with true-up mechanism but no pure fuel adjustment clause, vertically integrated electric utilities generally are assigned a risk factor between 25% and 50%. In jurisdictions where recovery of PPA-related capacity costs is guaranteed by a legislative mechanism, the timeliness of the mechanism affects the risk actor which may be as low as 0%. See "Request for Comments: Imputing Debt to Purchased Power Obligations," Standard & Poor's, November 1, 2006. Merchant generators are assigned a higher risk factor than vertically integrated regulated

of 100%.[26] The risk factor multiplied by the PV of the fixed capacity payments equals the amount of imputed debt that is added to the utility's reported long-term debt for the purpose of calculating financial ratios.

Imputed interest expense is calculated by multiplying the calculated amount of imputed debt by an interest rate. S&P changed its methodology to use the utility's average embedded cost of debt as the discount rate instead of a standard 10 percent.[27] The imputed interest expense is added to the utility's interest expense for the purpose of computing ratios. Finally, S&P determines imputed depreciation as the risk factor times the capacity payment minus the imputed interest expense. Example 1 below illustrates the process.

Example 1:

Assume that Utility ABC enters into a 20-year PPA that has annual capacity payments of $39.2 million. Utility ABC has embedded cost of debt of 6.7%. Finally assume that Utility ABC has been assigned a risk factor of 25% from S&P.

Using a discount factor of 6.7%, the PV of the 20-annuity would be about $425 million. In the first year, S&P imputes debt of about $106 million ($425 million x 25%) and an interest expense of approximately $7 million ($106 million x 6.7%). Finally, S&P imputed depreciation would be about $2.7 million ($39.2 x 25% -$7 million of interest expense) in the first year.

B. FINANCIAL RATIOS CONSIDERED BY S&P

The calculation of imputed debt and imputed interest expense results in an *adjusted balance sheet* and an *adjusted income statement* that are then used to calculate the utility's financial ratios. Currently, S&P relies primarily on three ratios plus qualitative factors to evaluate a utility's credit worthiness or default risk. The three key ratios[28] are

utilities, and tolling contracts are assigned a risk factor of 100%. See "Imputed Debt Calculations for U.S. Utilities' Power Purchase Agreements," Standard & Poor's, March 30, 2007.

[26] See, *Standard & Poor's Encyclopedia of Analytical Adjustments for Corporate Entities*, July 9, 2007.

[27] See, "Imputed Debt Calculations for U.S. Utilities' Power Purchase Agreements," Standard & Poor's, March 30, 2007.

[28] A detailed description of each ratio can be found in S&P's *Corporate Ratings Criteria 2007.*

(1) Debt to total capital,

(2) Funds from Operations (FFO) to average total debt,[29] and

(3) FFO interest coverage = FFO / (interest expense).

In the past, S&P also considered the Earnings before Interest and Taxes (EBIT) interest coverage ratio, but this ratio has been de-emphasized.

While other credit rating agencies have been less forthcoming about their methodology, all have publications that indicate that they take debt equivalence seriously. For example, "Fitch policy dictates that operating leases be capitalized"[30], and Moody's explicitly includes "operating lease adjustment," "under-funded pension liabilities" and "other debt-like items" in their adjusted debt amount.[31] Both Moody's and Fitch discuss the impact of PPAs in their publications regarding electric utilities although both seem to generally be less concerned about the impact of PPAs than is S&P.[32] In addition, it is noteworthy that utilities generally have comparable ratings from the different rating agencies, and utilities frequently furnish the same non-public information regarding their PPAs to all credit rating agencies.

IV. IS DEBT EQUIVALENCE A REAL PROBLEM?

A key concept in finance is that financial risk increases with leverage (i.e., the use of debt), and as a company increases its financial leverage, its cost of equity also increases. Therefore, a company's financial risk depends on the manner in which the company finances its operations. The more debt the

[29] Average total debt is usually calculated as the average debt over the past 12 months.

[30] Fitch Global Power Methodology and Criteria: *Debt-like obligations and contracts other than funded debt*, April 2004.

[31] Moody's Investor Service, *Ratings Methodology: Global Regulated Electric Utilities*, March 2005.

[32] See, for example, Moody's Investor Service, *Ratings Methodology: Global Regulated Electric Utilities*, March 2005, and Fitch Ratings, *U.S. Utility Financial Peer Studies. Investor-Owned and Public Power Utilities*, June 2005.

company has in its capital structure, the greater its financial risk. If a utility builds a power plant, an asset appears on its balance sheet along with the associated sources of financings, either equity, debt, or both. If a utility enters into a capital lease, an asset and an offsetting long-term liability appear on its balance sheet. Similarly, if a utility enters into a long-term operating lease or PPA, it has made a commitment to make fixed payments as if it had incurred a debt obligation, but no debt appears on its balance sheet.[33] The addition of a PPA (or portfolio of PPAs) and the associated fixed payments create a debt-like obligation and increases the utility's financial risk just as would the addition of debt to the utility's capital structure. The PPA payments decrease the utility's financial flexibility and increase the variability of the return on the utility's equity. S&P merely recognizes the underlying economics of the situation by adding a "debt equivalent" amount when it assesses the utility's financial strength.

Additional evidence of an increase in financial risk by the buyer of PPAs is the reduction of risk for the seller. Electric generating plants built by IPPs without long-term PPAs are considered to be of high risk (as discussed by Fitch, reported in Section II above). Signing a long-term contract with a credit-worthy utility considerably lowers the risk premium the plant's investors would have to pay to finance the project. In fact, having a long-term contract in place is often the only way a potential power plant builder can finance the investment. Fitch recognizes this:[34]

> The traditional method for independent generators was to rely on the strength of a PPA with a creditworthy off-takers (usually a utility) to help finance the construction cost of a new power plant. Take or pay contracts or firm capacity payments under the PPA would allow the developer to raise debt financing for the project, either using single asset project financing or under a portfolio financing approach. In general, power developers of this

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Standard & Poor's, *Fuel And Purchased Power Cost Recovery In The Wake of Volatile Gas And Power Markets - - U.S. Electric Utilities To Watch*, March 22, 2006,

[33] The asset from the regulator's promise to allow the recovery of the PPA costs does not appear on the balance sheet either, but the PPA payments represent a contractual obligation the utility cannot avoid while recovery of the PPA costs is uncertain. It is precisely the contrast between the commitment to make the PPA payments and the uncertainty of full cost recovery that is creating the increased financial risk.

[34] Fitch Rating, "Stimulating Generation Additions in Deregulated States," *Corporate Finance*, Nov. 4, 2005, p. 2.

> type have lower credit rating than those of the power purchaser. These developers can raise financing on more favorable terms if they can take advantage of the credit enhancement that comes from contractual cash flows from credit worthy counterparties.

Clearly, if the PPA seller has less risk, the PPA buyer and its customers have more. Risk has been transferred to the utility and its customers. The distribution of the transferred risk between the utility and its customers depends upon the strength of the cost recovery mechanisms in place. The more uncertain is full recovery of the costs of the PPA, the more risk the utility bears.

Although the use of leverage through fixed-cost capital, operating leases, or PPAs can be advantageous and reduce costs, it also increases financial risk due to the fixed contractual obligations associated with the leverage. PPAs, like debt, create a fixed obligation that revenues must support before any earnings can be made available to common shareholders. The credit rating agencies (S&P, Moody's and Fitch) have noted that the commitment to pay for these contract costs increases the financial risk of the utilities involved. Although the rating agencies' specific concern is that the risk of default on the utility's debt could be adversely affected by the requirement to make payments on the PPAs, the increased financial risk affects the risk (and required return) of the utility's equity capital as well. Investors' recognition of the presence of imputed debt affects the terms and costs under which the utility can raise debt and equity capital.[35] Therefore, it is essential that regulators also consider the presence of such obligations. Because S&P (and possibly the other rating agencies) determine the risk factor for a utility based in part on the regulatory treatment of purchased-power costs in the jurisdiction in which the utility operates, legislative and regulatory policy directly affect the magnitude of the imputed debt.[36] The additional leverage from PPAs influences the utility's cost of equity, the terms under which it can raise debt, and

[35] One indication that investors consider the presence of off-balance sheet obligations such as imputed debt to be important is that Generally Accepted Accounting Principles ("GAAP") currently require companies to disclose information about upcoming operating lease payments as well as the funding status of pension obligations.

[36] Fitch Ratings and Moody's also consider the likelihood of cost recovery. See, Fitch Ratings, *Global Power Methodology and Criteria: Debt-Like Obligations and Contracts Other Than Funded Debt*, April 2004 and Moody's, *Ratings Methodology: Global Regulated Utilities*, March 2005.

possibly the terms under which it can sign additional PPAs. At the margin, if a utility is deemed not to be creditworthy, it may not be able to raise debt or sign PPAs under reasonable terms.

In a recent publication, S&P illustrated how the regulatory environment and fuel/purchased power interact. Rating the regulatory recovery mechanism from "Historically Challenged" through "No or Weak Fuel Adjustment" to "Rate Freeze" and operating risk from Low to High, S&P indicated that entities with High Operating Risk in a "Rate Freeze" environment are at high risk for cash flow volatility and thus credit risk. The study identified six utilities as being at "considerable risk."[37]

The higher the level of purchased power and imputed debt, the greater the potential impact on adjusted utility financial ratios and ratings. The S&P adjustments to existing debt and the resulting calculation of key ratios can have the following effects on a utility:

a. Consideration of the cost of imputed debt affects integrated resource planning in the buy-versus-build decisions.
b. For some utilities, it may impede credit rating upgrades or lead to debt rating downgrades that would, in turn, lead to
    1. Restricted borrowing capacity and/or higher costs of capital for utilities and customers;
    2. Restrictive prepayment terms with fuel and purchased power counterparties; and
    3. An overall decrease in market value as utility common equity share price and debt price may be ultimately impacted.

Because all of the above affect the utility's financing and operating decisions, it is important to recognize and to mitigate the potential adverse effects of imputed debt. In particular, the risk transfer from power generators to utilities through long-term PPAs must be acknowledged and taken into account in regulatory proceedings.

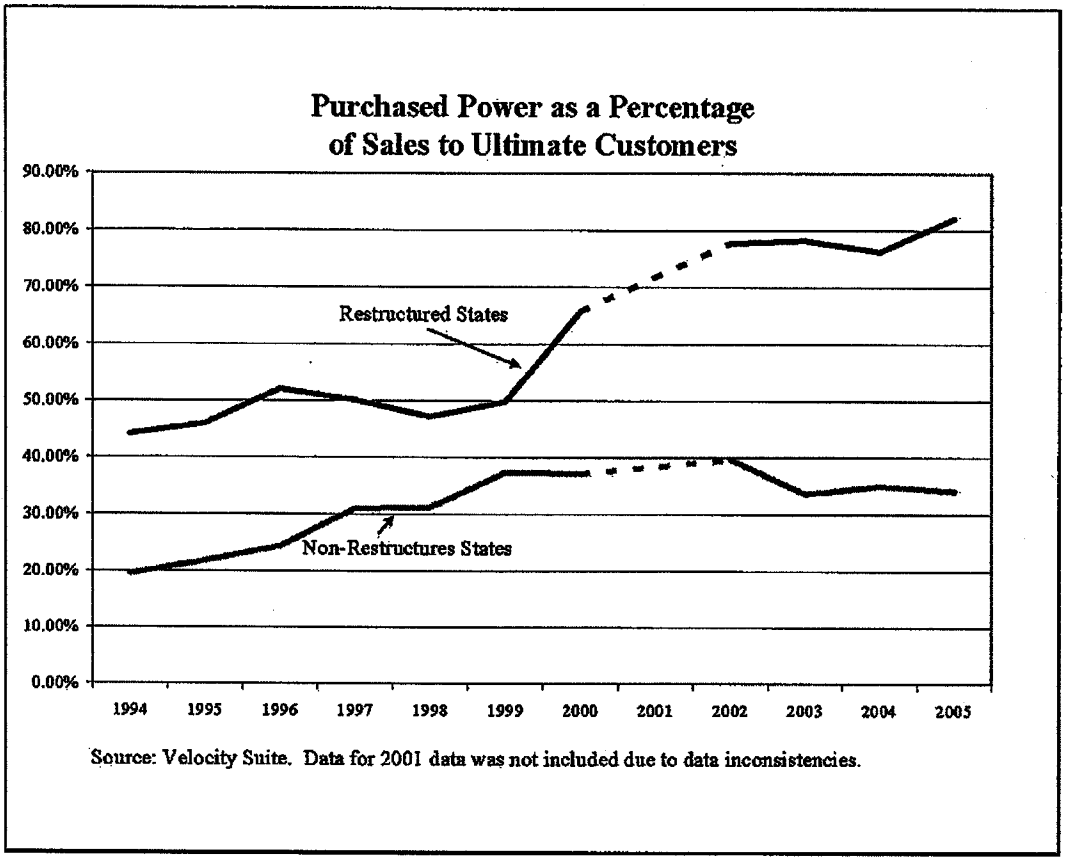
[37] Standard & Poor's Credit Ratings, *Fuel and Purchased Power Cost Recovery in the Wake of Volatile Gas and Power Markets- - U.S. Electric Utilities to Watch*, March 22, 2006.

V. HOW BIG A PROBLEM IS IMPUTED DEBT?

Long-term wholesale power purchase contracts have been a source of supply for regulated utilities for many years, but before the 1980's most traditionally regulated utilities planned to meet their obligation to serve through their own generation resources. Growth in long-term purchased power contracts was spurred by PURPA policies in the 1980s and became wide reaching after the Energy Policy Act of 1992 began the process of opening access to the FERC-regulated transmission grid. Over the last twenty years, IPPs have become major builders of power plants, owners of existing generation resources, and potentially low-cost new resources although the progress in this regard has been neither as smooth nor extensive as originally envisioned.

Regardless, the percentage of the power that utilities procure through PPAs has increased, particularly in jurisdictions where utilities have divested generation assets or where jurisdictions have levied a requirement that a specified portion of a utility's power supply be from "renewable" energy resources. Currently 24 states and the District of Columbia have adopted renewable energy standards requiring that a fraction of the state's electricity be supplied by renewable energy resources.[38] California recently advanced its goal of having 20 percent of its energy supply from renewable resources to 2010 from 2017, and it also increased the goal for 2020 to 33 percent from renewable energy sources. The vast majority, if not all, renewable resources are expected to be developed under long-term, fixed-price PPAs. See Appendix A for a review of recent state precedent on this issue.

[38] Edison Electric Institute as of June 7, 2007.



The graph above clearly shows that the percentage of sales to ultimate customers from PPAs has increased over time. In addition, S&P recently published tables that show how S&P adjusts a utility's financial ratios to account for off-balance sheet liabilities.[39] For the seven companies for which S&P provides data in the report, the average book debt-to-capital ratio was about 58 percent prior to S&P's adjustments and about 63 percent after S&P's adjustments. In other words, the average debt-to-capital ratio used by S&P to evaluate the companies' credit rating is five percentage points higher than prior to S&P's adjustments. Depending on the business risk profile of the utility in question, this increase in the debt ratio could result in the utility's ratios being consistent with a lower credit rating.

[39] "S&P Introduces Reconciliation Tables to Show Analytical Adjustments to Global Utilities' Financial Statements," *S&P Credit Ratings, Credit FAQ*, October 11, 2006. This document was prepared prior to S&P's adoption of its most recent practices for determining imputed debt.

For example, if a utility currently has an "Aggressive" financial risk indicator based upon its financial ratios, a change from a 58 percent to debt-to-capital to one with 63 percent places the utility in the "Highly Leveraged" financial risk indicator category for that ratio. Even if the utility had one of the two highest S&P business risk profiles of "Excellent" or "Strong", the change from "Aggressive" to "Highly Leveraged" changes the utility's likely credit rating from a low BBB to a low BB.[40] Other combinations of changes in financial ratios that could result in a change in the financial risk indicator could have similar effects. Of course, the rating agencies all caution against relying strictly on ratios to estimate the company's likely credit rating, but because a credit downgrade (particularly one from BBB to BB) would materially affect the terms and costs under which the utility could raise capital, it is important for ratepayers, the company and the regulator to be aware of the issue - imputed debt can be a big problem.

VI. MITIGATION OF THE IMPACT OF IMPUTED DEBT

Imputed debt increases a utility's financial risk and weakens its financial ratios. If the credit ratios weaken enough, the utility's credit rating may be downgraded or may be prevented from being upgraded. The increased cost of debt from a credit rating downgrade would be clear evidence of the adverse impact of imputed debt, but if there were no credit down grade, is there any effect from imputed debt?

Yes. Debt holders and equity holders will require a higher return to compensate for the increased risk of default and increased financial risk.[41] Debt ratings are discrete, but the range of ratios for any particular rating is continuous. As a company's ratios weaken, the utility's credit strength approaches the next lower credit rating. If the ratios are allowed to continue to deteriorate, the credit rating will ultimately be

[40] See "U.S. Utilities Ratings Analysis Now Portrayed in the S&P Corporate Ratings Matrix", Standard & Poor's, *Ratings Direct,* November 30, 2007.

[41] Even though both the cost of debt and the cost of equity increase, the overall after-tax weighted-average cost of capital ("ATWACC") will remain constant unless the increase in financial risk is sufficiently large to move the

downgraded. Moreover, the utility's credit ratios are known to the market. As the ratios weaken (strengthen), debt costs will increase (decrease) commensurately even though the credit rating has not yet been affected. The same logic applies to the cost of equity as acknowledged by, for example, the California PUC.[42] As financial risk increases, investors will require a higher expected rate of return on the company's stock. The increased cost of debt and equity from imputed debt cannot be avoided because the market will require compensation one way or another.[43]

Recognition by the regulator of the increased financial risk resulting from signing long-term or Evergreen PPAs[44] leads to the question of "what the regulator can and should do to mitigate the effect of imputed debt on the utility and rate payers?"

One task for regulators is to ensure that decisions regarding whether the utility should build a generator or sign a PPA are not unfairly weighted in favor of a PPA by ignoring the risk transfer to the utility. Ignoring the increased financial risk inherent in signing a long-term (or an evergreen) PPA would risk skewing the competition in favor of the PPA.

A. Methods to Mitigate the Negative Financial Effects of Long-Term PPAs

The overall goals of mitigating the negative effects of imputed debt should be to insure that investors, bondholders and equity holders, are treated fairly, while at the same time ensuring that the utility's

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company into financial distress. Companies in financial distress frequently have a higher cost of capital than would be possible if the company had an investment grade credit rating.

[42] See, for example, California PUC, *Decision 04-12-048, Interim Decision*, ("CA D.04-12-048"), Rulemaking 01-10-024, Dec. 14, 2004, p. 83. See Appendix A for further explanations.

[43] From a theoretical point of view, this statement is not generally controversial, but it is difficult to substantiate empirically. The problem is that estimating the cost of capital is difficult. All estimation methods are subject to estimation error so distinguishing the effect of imputed debt on the cost of capital from other factors is hard. A full explanation of the reasons is beyond the scope of this paper.

[44] As noted earlier, a series of short-term PPA contracts is termed "evergreen" when it is expected that the contracts will be replaced with an equivalent contract on a continuous basis as one contract expires.

customers are not overcharged. Although these goals are not controversial, the implementation of mechanisms that achieve them requires balancing the needs of investors and customers.

One method by which regulators can reduce the amount of imputed debt that results from a PPA is by adopting automatic cost recovery options that may influence S&P (and perhaps the other credit rating agencies) to reduce the risk factor assigned to the utility. For example, if the utility's risk factor were reduced from 50 percent to 25 percent, the amount of imputed debt would be reduced by 50 percent (i.e., 25/50). In other words, the regulator can reduce or perhaps eliminate the financial risk imposed on a utility from PPAs by adopting measures that decrease the level of uncertainty regarding full recovery of the costs of the PPA.

The remainder of the discussion focuses on mitigating the effects of imputed debt from having signed a long-term PPA. Focusing on the increased financial risk or the weakened credit ratios suggests that there are two broad approaches to mitigation.[45] The first is to compensate the utility for the increase in financial risk, and the second is to restore one or more of the weakened financial ratios to its preexisting level prior to entering into the PPA.

Compensating for financial risk is the simplest (and generally the least expensive) way is to mitigate the effect of imputed debt, and this method is usually appropriate for utilities that have an investment grade credit rating. For non-investment grade utilities (or utilities that may suffer an imminent credit downgrade without mitigation) additional compensation based upon restoring some of the company's credit ratios may be appropriate. Regardless of the method chosen, it is essential that the utility's credit rating not be allowed to be adversely affected by signing long-term PPAs, because this would clearly

[45] The credit rating agencies have taken no position on whether or how mitigation for the increased financial risk from PPA contracts could be provided. Some states such as Wisconsin, Colorado and Florida have essentially adopted mitigation in the form of an increase in the allowed regulatory equity ratio.

increase the cost of the utility's debt (and its equity). The remainder of this section discusses the two broad approaches to mitigating the effects of imputed debt.

1. Mitigation Focused on the Increased Financial Risk

This first broad approach is best viewed a being part of a general rate proceeding. If a utility's credit rating is currently investment grade and not in danger of becoming non-investment grade, mitigation of financial risk is sufficient. To understand this approach, keep in mind that the return on equity (or ROE) investors require is a function of both the business risk and the financial risk of the utility in question. Imputed debt increases the financial risk of the company and thereby increases the required return on equity. There are two basic ways to compensate for the increased financial risk: the company can substitute equity for debt to restore the adjusted balance sheet (the balance sheet including imputed debt) to its pre-contract ratios of debt and equity, or the allowed ROE for the entire existing equity rate base can be increased. These two methods are discussed in more detail below.

a) Increase the Amount of Equity in the Rate Base

Signing a long-term PPA is equivalent in some ways to financing a new investment completely with debt. As a result, the ratio of debt to equity in the company's "adjusted" balance sheet is increased. For example, consider a utility's whose rate base consists of 45 percent equity and 55 percent debt before a contract was signed, and after signing the contract, whose adjusted balance sheet consists of 41 percent equity and 59 percent debt. In other words, the imputed debt from the PPA increased the adjusted debt ratio by four percentage points.[46] An obvious solution is to add enough real equity and reduce real debt to restore the *adjusted* capital structure to its pre-contract ratio of debt and equity.

To implement this approach, the utility would first calculate the total amount of imputed debt from its PPA contracts.[47] The utility could then issue an amount of equity and reduce an equivalent amount of actual debt that restores the adjusted capital structure to the level before any debt was imputed or to a level that is deemed appropriate for the utility in question.[48]

For this approach to work, the regulator must allow an increase in the equity component of the rate base without simultaneously reducing the allowed ROE. The regulatory capital structure (with no recognition of imputed debt) now has a higher percentage of equity than it did before signing the PPA. The allowed rate of return on the adjusted rate base must be sufficient to compensate the utility's investors for the financial risk they carry from the "on the books" debt as well as the "off the books" (i.e., imputed) debt. The mitigation benefit would be eliminated if the allowed rate of return were reduced as soon as additional equity was issued by the utility. This approach restores the utility's debt ratio and its Earnings Before Interest and Taxes (EBIT) interest coverage ratio but will not restore its FFO/interest ratio and FFO/average debt ratio exactly.[49] The following example illustrates this point using S&P's calculation for imputed debt, depreciation[50] and interest expense.

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[46] In S&P's publication, *S&P Introduces Reconciliation Tables to Show Analytical Adjustments to Global Utilities' Financial Statements, op. cit.*, the average "S&P adjusted" capital structure included approximately five percent more debt than did the non-adjusted capital structure.

[47] If the amount of imputed debt were expected to vary substantially over time, it may be more appropriate to estimate an average or levelized amount of imputed debt, so that the amount of compensating equity would not have to change each year.

[48] A variation on this method is to establish a hypothetical capital structure and allow a return on the hypothetical equity component that compensates for the increased financial risk. This will be discussed in the second broad method.

[49] In general, the FFO/Interest ratio will be over or under restored depending upon the starting values of the ratio.

[50] In the examples, average imputed depreciation (equivalent to straight line depreciation) is used. This is a simplification because in the S&P method imputed depreciation expense varies each year which makes the calculations more complicated.

Example 2: Recall Utility ABC had entered into a PPA with an amount of imputed debt of $106 million under S&P'S methodology. Assume that Utility ABC had a $1,000 million rate base consisting of 45 percent equity ($450 million) and 55 percent debt ($550 million).

Table 1

Regulatory Capital Structure Without Imputed Debt		
Debt	$550	55%
Equity	$450	45%
Total	$1,000	100%
Adjusted Regulatory Capital Structure Reflecting Imputed Debt		
Debt	$656	59%
Equity	$450	41%
Total	$1,106	100%

As shown in Table 1, the "adjusted" rate base ($1,106 million) consists of $450 million in equity but now $656 million in debt with an equity ratio of 41 percent and a debt ratio of 59 percent. To restore the adjusted rate base to its pre-contract values would require that the utility issue $47 million in equity and recall $47 million in debt resulting in an adjusted balance sheet of $608 million debt and $498 million in equity. See Table 2.

Table 2

Restored Capital Structure to Pre-Contract Level (with imputed debt)				
			Rate	ATWACC
Debt	$608	55%	6.70%	2.21%
Equity	$498	45%	10.50%	4.73%
Total	$1,106	100%		6.94%
Restored Capital Structure (without imputed debt)				
			Rate	ATWACC
Debt	$502	50%	6.70%	2.02%
Equity	$498	50%	10.50%	5.23%
Total	$1,000	100%		7.25%

As can be seen in Table 3, the additional equity fully restores the Debt to Total Capital ratio and the EBIT Interest Coverage ratios, but the other ratios are not fully restored.

Table 3

Ratios Before and After PPA	Before PPA	With PPA and No Mitigation	With PPA and Mitigation
Debt to Total Capital	55%	59%	55%
FFO to Total Debt	0.27	0.23	0.26
FFO Interest Coverage	5.0	4.5	4.9
Adj. EBIT Interest Coverage	3.14	2.8	3.14

While the approach of issuing compensating equity is financially sound, it cannot easily be implemented on a contract by contract basis, because the cost of issuing small amounts of equity would be prohibitive. This method is best viewed as a means to mitigate a portfolio of PPAs in the context of a general rate case.

b) Increase the Allowed Return on Equity

The second method to mitigate the increased financial risk from imputed debt is to increase the allowed return on equity. The increased return also mitigates some of the adverse impact on the utility's financial ratios, but does not fully restore any ratio. The question is how much to increase the allowed return on equity? The answer to this question is relatively easy to estimate and is based upon the fact that a company's after-tax weighted-average cost of capital or ATWACC is constant for changes in capital structure within a broad middle range of capital structures for the companies in an industry.[51] Consider the following equation to calculate the ATWACC:[52]

$$ATWACC = r_D \times (1 - T_C) \times D + r_E \times E \qquad (1)$$

Where r_D = market cost of debt,

[51] For a complete discussion of this topic see "The Effect of Debt on the Cost of Equity in a Regulatory Setting," prepared by *The Brattle Group* for the Edison Electric Institute, January 2005.

[52] Note that this equation assumes that only debt and equity are in the capital structure, but one can add preferred equity to the equation if appropriate.

r_E = market cost of equity,
T_C = corporate income tax rate,
D = percentage of debt in the capital structure, and
E = percentage of equity in the capital structure.

The cost of equity consistent with the ATWACC, the market cost of debt and equity, the marginal corporate income tax rate and the amount of debt and equity in the capital structure can be determined by solving the equation above for r_E.

The change in the return on equity necessary to compensate for the increase financial risk from the PPA can be determined by first, calculating the pre-contract ATWACC based upon the pre-contract allowed rate of return on equity, debt costs and tax rate, and then calculating the new allowed return on equity that results in the same pre-contract ATWACC *after* the amount of imputed debt is added to the capital structure. This method results in exactly the same revenue requirement as the first method, but none of the utility's ratios would be fully restored to their pre-contract values because there is no reduction in interest expense from substituting equity for debt. This method recognizes the increased financial risk as if the utility had financed its investment completely with debt.[53]

Example 3
Recall Utility ABC had a capital structure consisting of $550 million debt and $450 million equity for a rate base of $1,000 million prior to entering into a PPA with an amount of imputed debt of $106 million (using S&P's methodology). Also assume that Utility ABC prior to entering into the PPA had an allowed return on equity of 10.50% and an embedded cost of debt of 6.7 percent. As shown in Table 2 above the pre-contract ATWACC fro Utility ABC was 6.94%. Table 4 illustrates how much the allowed return on equity should be increased to compensate the utility for the financial risk represented by the PPA.

[53] A depreciation expense equal to the annual capacity payment minus the imputed interest expense is added to the numerator in the FFO ratios. Therefore, the impact on these ratios has been moderated with S&P's recently revision of its imputed debt methodology.

Table 4

	Dollar	Percent	Cost	ATWACC
Regulatory Capital Structure Without Imputed Debt				
Debt	$550	55%	6.70%	2.21%
Equity	$450	45%	10.50%	4.73%
Total	$1,000	100%		6.94%
Adjusted Regulatory Capital Structure Reflecting Imputed Debt and Constant ATWACC				
Debt	$656	59%	6.70%	2.38%
Equity	$450	41%	**11.19%**	4.55%
Total	$1,106	100%		6.94%
Regulatory Capital Structure Without Imputed Debt at Higher ROE				
Debt	$550	55%	6.70%	2.21%
Equity	$450	45%	**11.19%**	5.03%
Total	$1,000	100%		**7.25%**

Notice that the ATWACC is identical in Table 2 and Table 4, but the cost of equity has increased from 10.50% to 11.19%. Notice also the increase in the overall revenue requirement is $5.17 million for both. The increase in dollar return on equity is (11.15% - 10.50%) multiplied by $450 or $3.10 million after tax which result in $5.17 million before tax ($3.10/ (1-tax rate)) assuming a marginal income tax rate of 40 percent.

Increasing the allowed return on equity does not fully restore any of the financial ratios as can be seen in Table 5 below, but increased equity return is compensation for the increased financial risk. The advantage of this method is that the cost of issuing new equity is avoided.

Table 5

Ratios Before and After PPA

	Before PPA	With PPA and No Mitigation	With PPA and Mitigation
Debt to Total Capital	55%	59%	59%
FFO to Total Debt	0.27	0.23	0.24
FFO Interest Coverage	5.0	4.5	4.5
Adj. EBIT Interest Coverage	3.1	2.8	2.9

2. Mitigation Focused On Restoring Financial Ratios

The second broad approach focuses on (partially) restoring some of the financial ratios to their pre-contract values. Because this approach is, in general, more expensive for rate payers than the first approach, it is only appropriate for a utility that does not have an investment grade credit rating or which is in danger of a downgrade to a non-investment grade rating if the negative effects of signing long-term PPAs are not addressed.

The distinguishing feature of the second approach is that mitigation is achieved by allowing a return on an amount of "imputed equity" that is calculated to offset the negative effects of imputed debt. The amount of imputed equity necessary can be targeted at compensating for any of the financial ratios. Unfortunately, there is no one solution that will restore all of the ratios that S&P relies on or the three ratios most heavily relied upon because calculation of the ratios relies upon different parts of the balance sheet and income statement. Therefore, the second approach requires a decision on which ratio should be restored or alternatively on what hypothetical capital structure to allow a return.

Because this method focuses on the utility's financial ratios, it can be applied as a "contract adder" on a contract by contract basis. Unlike the case in which new equity is issued or the appropriate ROE for the entire rate base is adjusted, the second method allows an equity return on an amount of imputed equity so there are no additional transactions costs with this method other than the process of approving the PPA and the determining the associated amount of imputed equity. Nor is it necessary to have a general rate case because the equity return on the imputed equity is simply the most recent commission-allowed ROE.

The "Financial Ratio Method," or ratio restoration, is designed to provide sufficient additional equity return to restore the utility's financial ratios to their pre-contract values over time. As mentioned above, S&P focuses on three financial ratios when evaluating the impact of imputed debt.[54] Restoring each

[54] S&P has de-emphasized the EBIT ratio. See S&P's Research: "New Business Profile Scores Assigned for U.S. Utility and Power Companies: Financial Guidelines Revised," June 2, 2004.

particular ratio requires a different amount of imputed equity. Although the EBIT interest coverage ratio is not currently among S&P's key financial ratios, it is the easiest (least expensive) ratio to restore to its preexisting value. Restoring the EBIT ratio will also partially restore the other three ratios. Assuming that the additional earnings are invested in additional assets that are recognized in the rate base, over time the other three ratios will also improve although they need not ever be fully restored. In general, the most expensive ratio to restore is the FFO/debt ratio.

One way to view this approach is to convert the PPA and its resulting imputed debt into a "mini-firm". The PPA generates the imputed debt and depreciation. The task is to determine an amount of imputed equity on which to earn an equity return that will restore the target ratio. Because the present value of future contract payments declines over the life of the contract, so does the amount of imputed debt. Therefore, the amount of imputed debt declines as well.

Implementing the financial ratio method requires the following steps:

- First, calculate the amount of compensating equity return that restores the target ratio when imputed interest expense and imputed depreciation are considered. The return earned on the compensating equity is assumed to be the same as the utility's allowed rate of return on equity rate base from the most recent rate case.

- Second, calculate an adder to the cost customers pay per MWh (rate) for the contract(s).

Example 4: Continuing the previous example, assume that the utility expects to receive about 1.4 million MWh per year from the PPA contract. It is possible to calculate the additional cost per MWh for each year the contract is in effect to restore the EBIT interest expense ratio. This is done in Table 6 below.

Table 6

Year	Present Value of Capacity Payment	Imputed Debt	Compensating Hypothetical Equity	Compensating Before-Tax Equity Return	Contract Adder ($/MWh)
1	$425.1	$106.29	$87.0	$15.2	$10.9
2	$414.4	$103.61	$84.8	$14.8	$10.6
3	$403.0	$100.75	$82.4	$14.4	$10.3
4	$390.8	$97.70	$79.9	$14.0	$10.0
5	$377.8	$94.45	$77.3	$13.5	$9.7
6	$363.9	$90.97	$74.4	$13.0	$9.3
7	$349.1	$87.27	$71.4	$12.5	$8.9
8	$333.3	$83.32	$68.2	$11.9	$8.5
9	$316.4	$79.10	$64.7	$11.3	$8.1
10	$298.4	$74.60	$61.0	$10.7	$7.6
11	$279.2	$69.80	$57.1	$10.0	$7.1
12	$258.7	$64.67	$52.9	$9.3	$6.6
13	$236.8	$59.21	$48.4	$8.5	$6.1
14	$213.5	$53.37	$43.7	$7.6	$5.5
15	$188.6	$47.15	$38.6	$6.8	$4.8
16	$162.0	$40.51	$33.1	$5.8	$4.1
17	$133.7	$33.42	$27.3	$4.8	$3.4
18	$103.4	$25.86	$21.2	$3.7	$2.6
19	$71.2	$17.79	$14.6	$2.5	$1.8
20	$36.7	$9.18	$7.5	$1.3	$0.9

In the table, the imputed debt is the present value of the capacity payments multiplied by 25% counting only the remainder of the contract. The compensating equity is calculated as Utility ABC's regulatory equity to debt percentage multiplied by the imputed debt. Compensating equity return is calculated as the after-tax cost of equity (10.5%) divided by (1 – tax rate) or (1 – 40%). Finally, the contract adder is calculated as the compensating equity return divided by the expected MWh per year.

As noted above this method restores the EBIT interest coverage ratio but it does not fully restore other ratios. Of course, as each year passes, the amount of imputed debt for a contract declines because there are fewer future contract payments, so the dollar amount of compensation also declines. This happens even though the formula to calculate the amount of mitigation is unchanged. Depending on the individual utility's circumstances, it may make sense to levelize the adder, so that the same dollar amount is added to the cost of electricity each and every year during which the contract is in effect. This method can be adjusted to focus on any of the other financial ratios. The required compensation will be greater depending upon which ratio is the focus of the compensation.

Example 4 Continued: Table 7 below shows the amount of compensating equity that is needed to restore each of the four ratios in the first year. Because this method envisions using imputed equity, the debt ratio is never affected.

Table 7

Equity Required to Restore Ratios	
	S&P Metholodogy
Debt to Total Capital	na
FFO to Total Debt	$220
FFO Interest Coverage	$220
EBIT Interest Coverage	$87

The EBIT Interest Coverage ratio requires the least compensation to restore. The reason that the two FFO ratios require the same amount of imputed equity is that the calculations assume imputed depreciation is recovered straight line as opposed to S&P's method for ease of exposition.

B. Comparison of Mitigation Methods

The advantage of the method utilizing imputed equity to offset imputed debt is it can be applied on a contract-by contract basis between rate cases and does not require the utility to issue additional equity. Restoring the three main financial ratios is generally more costly than compensating for financial risk, but hypothetical equity can restore any particular financial ratio. For a utility with a non-investment grade credit rating, restoring the financial ratios will help prevent a credit downgrade more than simply compensating for financial risk. However, both methods compensate the utility for the risk inherent in PPAs and improve its financial ratios relative to doing nothing. Focusing solely on the increased financial risk is less costly to consumers than is the financial ratio method, but it also takes longer to restore the company's other financial ratios to their pre-contract levels.

VII. CONCLUSION

<u>(1) Long-term purchase power agreements (PPA) transfer financial risk from the seller to the buyer.</u>

This is because PPAs obligate the buyer's future cash flow, just like a debt service obligation.

(2) Policy makers should be particularly sensitive to PPA-related risk transfer in situations where the utility's credit rating is minimally investment-grade. For such utilities, entering into PPAs without addressing debt imputation could trigger credit downgrades which push the utility below investment-grade - with consequences that are far more harmful to customers than downgrades to levels that are still investment-grade. The risk transfer from PPA contracts must still be considered for utilities which are strongly investment-grade although the consequences of a credit rating downgrade are not likely to be as severe.

(3) Regulatory policies which provide assurance of PPA cost recovery can effectively mitigate the impact of imputed debt on the credit rating of purchasing utilities. S&P's methodology, in particular, applies a risk factor to the debt calculation which is intended to reflect the probability that PPA costs will be fully recovered in rates. The greater the probability, the smaller the risk factor, and the smaller the amount of imputed debt from a particular set of contracts.

(4) There is no perfect solution to the problem of PPA-related risk transfer and imputed debt. There are at least three possible approaches to addressing the problem. Unfortunately, none simultaneously maximizes the protection of credit worthiness, while minimizing the cost to consumers.

(5) In competitive procurement situations, it is important that imputed debt be addressed in a competitively-neutral way. Imputed debt should not be used to exclude merchant generators from the market, but neither should it be ignored. Adjustments should be based on the true costs involved (e.g., by increasing bid prices by no more than is required to restore interest coverage ratios to pre-PPA levels).

APPENDIX A

TREATMENT OF IMPUTED DEBT IN CERTAIN STATES

This appendix discusses selected states where policy makers, i.e., legislatures or regulatory commissions, have looked at the issue of imputed debt, or debt equivalence, for long-term purchased power contracts. One application is in cost of capital hearings and deals with the impact of imputed debt on the financial strength of the utility, its regulatory capital structure, and the allowed return on equity. A second application is the mitigation of increased financial risk with a cost adder to the price upon signing specific long-term PPAs. A third area is in the evaluation of "buy versus build" situations[55] comparing the competitive bids of independent power producers and regulated utilities for new generation in states with hybrid generation markets.[56] Policy makers analyzing imputed debt generally recognize that credit rating agencies, especially S&P, calculate imputed debt and adjust critical financial ratios accordingly. The policy outcomes are varied, with some states providing for explicit mitigation of imputed debt, and some states choosing not to mitigate in the cases reviewed. States discussed here (California, Delaware, Florida, Nevada, New Mexico, and Wisconsin) have all considered how and

[55] A buy-versus-build situation occurs when a competitive procurement proceeding is held and the decision on which is the lowest cost alternative (i.e., lowest present value of future revenue requirements) includes making a choice between the lowest cost power purchase option in comparison with the utility's best self-build option. The utility's self-build option will include its proposed capital structure, which will help determine its final cost. The new generation addition would normally mirror that of the utility as a whole and leave the utility's financial risk profile unchanged. If, purely hypothetically, the utility were to use 100 percent debt financing with no additional equity and equity return, the utility's financial risk would go up, as measured by the S&P financial ratios. As a general proposition (before looking at the specifics of a given situation), the signing of the long-term PPA has the effect of increasing debt equivalence without increasing return (mediated through the imputed debt calculus discussed above). Therefore, in comparing that PPA alternative with self-build options at allowed capital structure, the mitigation of cost of imputed debt to the utility needs to be added to the contract the utility signs to make the comparison "apples to apples." See Standard & Poor's *Utilities & Perspectives*, "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements," May 2003 and, for an opposing view, Electric Power Supply Association, *Electric Utility Resource Planning - The Role of Competitive Procurement and Debt Equivalency*, prepared by GF Energy LLC, July 2005.

[56] A hybrid generation market, which, as discussed below, California has become and Delaware could now become under new law, is where resource procurement for new supplies is accomplished with open bidding among independent power producers and regulated, cost-of-service utilities.

whether to address imputed debt.[57] Brief summaries of these states' treatments are provided below. There is first an indicative discussion of the reasons why many states have not addressed imputed debt.

States for which Imputed Debt is not Currently an Issue

Although S&P applies its imputed debt methodology to all utilities issuing debt, state regulatory commissions or legislatures are not likely to consider imputed debt to be a material policy issue if the state's utilities do not have significant existing or prospective long-term PPAs. States in this situation include primarily states with a traditional industry structure where utilities own and continue to build all generation necessary to meet their obligation to serve. Additionally, in "retail access" states, of which there are currently seventeen, the utilities first obligation is to provide reliable, low-cost transmission and delivery service, and, in many such states, to purchase a substantial amount of electric power to meet their obligations as Provider of Last Resort ("POLR"). Most of the POLR contracts have historically been for short terms, generally three years or less.[58] Before S&P changed its methodology, such shorter term contracts generated little or no imputed debt. This has changed, and S&P now treats short-term contracts in an "evergreen" manner, i.e., assuming they will be renewed indefinitely and therefore warrant imputed debt treatment. Policy makers in retail access states are now likely to be asked to address the resulting effect of imputed debt on the credit ratings of the states' utilities.[59]

Moreover, heavy reliance on short-term contracts for power procurement does not appear to be a viable long-term policy for all of the retail access states for two reasons. First, the higher level of electric price volatility may be unacceptable to ratepayers and regulators, as experienced in the recent period of

[57] This discussion is not intended to be exhaustive. It omits discussion of several states where the discussion has begun, but where the authors are not aware of the final outcome, including OR, LA. UT is also omitted.

[58] Note: the term "state" is always used in these discussions to include the District of Columbia (DC), for convenience of exposition. The seventeen "retail access" states are: CT, DE, DC, ME, MD, MA, MI, NH, NJ, NY, OH, OR, PA, RI, TX, VA. The situation in DE may be changing, as discussed below.

[59] Standard & Poor's, "Imputed Debt Calculation for U.S. Utilities' Power Purchase Agreements," March 30, 2007.

natural gas price inflation and the resulting higher electric prices. Second, short-term contracts and spot market sales do not appear to provide strong enough incentives for investment in adequate new generation. The Fitch rating agency stated its view position on short-term contracts: ". . . the one-to-three-year term of such supply agreements is, in Fitch's view, too short to provide a financial foundation on which to fund the construction of new independent power generation."[60]

In contrast, there is little question that long-term contracts signed under regulatory guidance by financially sound utilities can be used to finance new power plants. Fitch goes also predicts that retail access states within regional transmission organizations (RTOs) may have to become more active and may well move toward hybrid market structures, with long-term procurement processes more akin to what are found in California. Moreover, the authors of this report conclude that the Fitch analysis recognizes the transfer of risk from the power producer to the purchasing utility by the signing of a long-term purchased power contract. This risk transfer is related to the risk that S&P identifies in its calculation of imputed debt for the contract buyer.

California

The Public Utilities Commission of California (CPUC) revised its policy recently so that utilities are no longer allowed to adjust (increase) independent power producers' (IPP) bid prices to account for the cost of risk transfer in comparing them to self-build options. The Commission continues to consider debt equivalence in determining utilities' costs of capital.[61]

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[60] Fitch Ratings,"Stimulating Generation Additions in Deregulated States," *Op. Cit.*, November 4, 2005, at p. 2. This was discussed above in Section II.

[61] CPUC, *Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison Company's, and San Diego Gas & Electric Company's Long-Term Procurement Plans*, Decision 07-12-052, December 20, 2007.

The CPUC previously had recognized that debt equivalence is a real economic cost that can impact a utility's credit rating and cost of borrowing, and had allowed utilities to use a 20% debt equivalence factor in comparing PPAs to self build options. In December, 2007 the Commission changed its policy out of concern that explicitly recognizing the cost of PPA risk transfer "...creates a disparity between the treatment of PPAs and utility-owned projects in the procurement process..." because no such adder is applied to self-build options. For the 2005 test year, the Commission did approve a 4% increase in southern California Edison's preferred equity ratio, and a corresponding decline in SCE's long-term debt ratio (all measured on a ratemaking basis). More recently, the Commission has rejected attempts by San Diego Gas & electric to establish an automatic mechanism to increase SDG&E's equity ratio to offset the FIN(46) effects of PPAs.

In effect, the policy in California now is to ignore PPA risk transfer during procurement decision making and address its consequences after the fact: "We recognize that at some point, DE *may* reach a point where it can affect the utilities' credit rating and cost of capital, and it is not disputed in this proceeding that the potential effect of DE on credit ratings, if any, is an appropriate topic for the utilities' cost of capital proceedings." (Note that all three large California electric utilities have applied for rehearing of this decisions, so it is possible that the Commission will revise its policy once again.)

Delaware

Delaware has been among the states pursuing a policy of retail competition, but had the misfortune to end its capped-price transition period on May 1, 2006, after the recent inflation in electric prices. Apparently, the majority of residential and small commercial customers were forced to move to a higher priced "Standard Offer Service," which was procured through short-term auctions and that reflected the volatility that is inherent in a short-term strategy.

The General Assembly passed a revision to the restructuring legislation entitled "The Electric Utilities Retail Supply Act of 2006." The Act provides that all regulated electric distribution companies will henceforth be designated as the standard offer service supplier and returning customer service supplier in their respective territories. Moreover, the distribution companies now are given new opportunities and responsibilities to enter into long-term and short-term supply contracts, to own and operate generation facilities, to build generation and transmission facilities, to make investments in demand-side resources and to take any other Commission approved action to diversify their retail load supply [emphasis added]. This has ushered in the issue of imputed debt in an essential way.

On August 1, 2006, in response to Commission directives, Delmarva Power and Light (Delmarva) filed a draft RFP. There has been a substantial amount of discussion about the terms and conditions of the RFP, particular in three areas: imputed debt cost factors in bid evaluation, credit and operational security requirements, and variable interest entity treatment under FASB Interpretation No. 46.[62] Delmarva has proposed that in order to account for the effect of imputed debt on its balance sheet and credit rating, there would be a cost adjustment added to each long-term bid. This adjustment would be based on an S&P calculation of imputed debt.

Delmarva argued that where a bid is compared with Delmarva's self-build option, the NPV of revenue requirements would generally include the impact of additional debt and equity in proportion to Delmarva's allowed capital structure and debt and equity costs from the most recent rate decision. The need to maintain the appropriate equity thickness is built into the cost structure of the self-build options. The cost adder puts contracts on a comparable footing in terms of mitigating the degradation in Delmarva's financial ratios.

[62] See New Energy Opportunities, Inc et al., *Analysis and Recommendations Regarding Delmarva Power and Light Company's RFP*, September 18, 2006, "Section viii. Imputed Debt Offset" and Concentric Energy Advisors, Inc.

On November 21, 2006, the Delaware Public Service Commission issued Order No. 7081, which found that Delmarva's (DP&L) imputed debt adjustment should be used in their RFP. The Order says[63]

> 145. We believe that the RFP should provide that DP&L will be permitted to assess the incremental equity amount to be equal to 30% of the net present value of the bid's capacity payment, and that a portion of the energy price may also be included if DP&L concludes that a portion of the bid's energy component would be imputed as debt by rating agencies in their assessment of DP&L's creditworthiness.

Florida

The Florida Commission first addressed imputed debt in 1999 by approving a stipulation and settlement that explicitly mitigated the impact of imputed debt. The settlement did so by setting the level of equity that Florida Power & Light (FP&L) was allowed in its capital structure for surveillance reporting requirements and all regulatory purposes, on a basis that was adjusted for imputed debt.[64] This policy of having an explicit equity adjustment in the capital structure was continued with the approval of subsequent orders, including that in 2005, where in Paragraph 15 states:[65]

> 15. For surveillance reporting requirements and all regulatory purposes, FPL's ROE will be calculated upon an adjusted equity ratio, as follows. FPL's adjusted equity ratio will be capped at 55.83% as included in FPL's projected 1998 Rate of Return Report fro surveillance purposes. The adjusted equity ratio equals the common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations. The amount used for the off-balance sheet obligations will be calculated per the Standard & Poor's methodology. [Emphasis added]

Thus, the Florida Commission mitigates the financial impact of imputed debt by increasing the utility's

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Assessment of the Risks of the Independent Consultant's Proposed Modifications to Delmarva's RFP for New Generation Resources, Oct. 30, 2006.

[63] Delaware PSC, PSC Docket No. 06-2111, Order No. 7081, Nov. 21, 2006, p. 4.

[64] Florida Public Service Commission, *Order Approving Stipulation and Settlement*, Docket No. 990067-EI, Order No. PSC-99-0519-AS-EI, issued on March 17, 1999.

[65] Florida PSC, *Order Approving Stipulation and Settlement*, Docket No. 050045-EI, Docket No. 050188-EI, Order No. PSC-05-0902-S-EI, Issued Sept. 14, 2005; and *Stipulation and Settlement*, Same Dockets, dated Aug. 22, 2005, Paragraph 15.

equity "thickness." The approach is based directly on the S&P methodology for calculating imputed debt. The Commission explicitly recognized the effect that purchased power contracts have on the utility's financial ratios as calculated by S&P. The Commission approved the 1999 settlement that capped FPL's adjusted equity ratio at 55.83 percent — which at that time equated to a ratio of 65.7 percent based on the regulatory books absent imputed debt.[66] Thus, to offset the greater financial leverage associated with its imputed debt, FP&L was allowed to increase its actual equity ratio as long as the "adjusted equity ratio" (i.e., the equity ratio calculated to include imputed debt) did not exceed 55.83%.

The Florida Commission also considered imputed debt in its approach to making long-term resource planning decisions. The Florida Commission requires its utilities to account for the costs that purchased power contracts impose on utilities through imputed debt.[67] To do this, FP&L employs an equity adjustment to calculate the additional costs associated with the amount of imputed debt based on S&P's imputed debt calculation for the specific contract under discussion. This cost is added to the cost of the contract for making comparisons with other resource options. The 1999 order approved the use of a 10 percent risk factor, noting that this was the factor then assigned by S&P.[68] However, in 2004 the Florida Commission increased the risk factor to 30 percent, explaining that six months earlier S&P had issued a report stating that it now applied a 30 percent risk factor in the determination of the consolidated credit profile of the FPL Group.[69]

Nevada

In 2001, Nevada adopted what was at the time one of the country's more aggressive renewable portfolio

[66] Order No. PSC-99-1713-TRF-EG, Docket No. 990249-ET, September 2, 1999, p. 9. See also Provision 4 of *Stipulation and Settlement*, Before the Florida Public Service Commission, Docket No. 990067-EI, March 10, 1999.

[67] F.A.C. Rule 25-22.081, paragraph 7.

[68] Order No. PSC-99-1713-TRF-EG, Docket No. 990249-ET, September 2, 1999, p. 9.

[69] Florida PSC, Order No. PSC-04-0249-TRF-EQ, issued on March 5, 2004, in Docket No. 031093-EQ

standards ("RPS"). The law requires that 15 percent of all electricity generated in Nevada be derived from new sources of renewable energy by the year 2013. This required that the state's utilities, Nevada Power Corp and Sierra Pacific Power Corp, sign a substantial number of new, long-term contracts for renewable power. Early progress was modest, in part because these utilities were emerging from a period of financial distress with below investment grade bond ratings, stemming from the western energy crisis.

In June 2005, the Nevada legislature passed Assembly Bill 3 ("AB3") that modified Nevada's RPS. The new law increased the target percentages for energy from renewable resources, now requiring that by 2015, 20 percent of all electric power be from renewable energy resources. At the same time, the legislature recognized that the goal of significantly increasing the number of renewable energy contracts signed would be difficult without proactively addressing the issue of imputed debt. The utilities were concurrently engaged in strong efforts to regain an investment grade bond rating. AB3 addresses imputed debt directly by requiring the following:[70]

7. The Commission shall adopt regulations that establish:

> (a) Standards for the determination of just and reasonable terms And conditions for the renewable energy contracts and energy efficiency contracts that a provider [of electric service] must enter into to comply with its portfolio standard.
>
> ***(b) Methods to classify the financial impact of each long-term renewable energy contract and energy efficiency contract as an additional imputed debt of a utility provider. The regulations must allow the utility provider to propose an amount to be added to the cost of the contract, at the time the contract is approved by the Commission, equal to a compensating component in the capital structure of the utility provider. In evaluating any proposal made by a utility provider pursuant to this paragraph, the Commission shall consider the effect that the proposal will have on the rate.*** [Emphasis added]

The Public Utility Commission of Nevada (PUCN) implemented this requirement in a set of rules, NRS 704.7821(7) (b).

In May 2006, Sierra Pacific Power Company (SPPC) filed for the approval of a renewable contract negotiated to partially meet the renewal portfolio standard. The filing included the request for mitigation of imputed debt through a cost adder, which followed SPPC's interpretation of the AB3. However, SPPC withdrew the request for mitigation of imputed debt of the contract in late summer of 2006, reserving the right to re-file. Therefore, at this time, there has been no test of whether the PUCN would approve any particular cost adder on a renewable contract as imputed debt mitigation based upon their interpretation of the 2005 law.

New Mexico

The New Mexico Renewable Energy Act (REA), at NMSA 1978, § 62-16-4(D), requires New Mexico's investor-owned electric utilities to file a procurement plan each year that includes the cost of any new renewable energy resource required to comply with the renewable portfolio standard ("RPS"). The 2007 Plan of Public Service of New Mexico (PNM) requested that the New Mexico Public Regulation Commission (NM Commission) approve both the "Biomass PPA," a long-term purchased power agreement for renewable energy from a biomass plant, and the recovery of the costs of the Biomass PPA.[71] In addition to the costs for capacity and energy, PNM sought approval to mitigate the financial impacts of imputed debt through the approval of an adder, which would be later collected in rates when the biomass plant was built and renewable power began to be supplied.

The statutory language on cost recovery for renewable energy, in NMSA 1978, § 62-16-6, states:

> (A), A public utility that procures or generates renewable energy shall recover, through the rate-making process, the reasonable costs of complying with the renewable portfolio standard. Costs that are consistent with commission approval of procurement plans . . .

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[70] See State of Nevada, Assembly Bill No. 3 – Committee of the Whole, Section 29.7 (b), p. 21. http://www.leg.state.nv.us/22ndSpecial/bills/AB/AB3_EN.pdf.

[71] Public Service Company of New Mexico, Notice of Filing of "Renewable Energy Portfolio Procurement Plan for 2007," Case No. 06-00340-UT, August 16, 2006.

shall be deemed to be reasonable.

PNM's proposal analyzed the Biomass PPA's imputed debt impacts in terms of the S&P methodology, which was used to determine the degree to which the three key financial ratios would be degraded (Funds from Operations (FFO) interest coverage; the FFO to Debt ratio; and the Total Debt to Total Capital ratio). The mitigation requested was a cost adder equal to the net return on a "compensating equity adjustment." This is the amount of equity that, if PNM were to issue and use to retire real debt, would restore PNM's debt-to-capital ratio to its pre-Biomass PPA level. The concept and formula used were generally the same as used in the state of Florida to make imputed debt adjustments discussed above.

However, the Commission approved only the energy and capacity costs of the Biomass Contract and denied approval of the cost of imputed debt in the context of this proceeding, which covered renewable plan and contract approval.[72] No party contested the fact that signing the Biomass contract would degrade PNM's financial ratios, other things equal. The Commission appears to have reasoned that the degradation of financial ratios in the degree indicated is not sufficient without evidence that a bond downgrade was likely to follow. Although PNM had an S&P rating of BBB/Negative, the Company did not contend that signing this long-term Biomass contract alone would be likely to change its credit ranking. The Commission also appeared to determine that the degraded financial ratios were also insufficient evidence that the cost of capital would increase, and therefore, rejected the cost adder sought. In accordance with the Recommended Decision of the Hearing Examiner, PNM was left with the opportunity to raise the issue of the financial impact resulting from the Biomass contract (and possibly other off balance sheets obligations) in another docket. The Recommended Decision states "While we deny PNM's request in this case concerning imputed debt, PNM will have a full and fair

[72] New Mexico Public Regulation Commission, *Final Order on Exceptions*, Case No. 06-00340-UT, Dec. 18, 2006. There are many other issues discussed.

opportunity to present this matter in its next rate case."[73]

Wisconsin

Wisconsin sets a common equity ratio target based on what they call a "Financial Capital Structure" that includes off balance sheet items (including imputed debt on PPA's) that supports, in their view, a given rating. This then sets the amount of equity that will be included in the "Regulatory Capital Structure" in setting rates. The effect is to allow the company to carry a thicker equity ratio and have it considered within the ratemaking process. In WPSC's last case its financial equity target was 52%. This ratio is intended to support a credit rating between an A and an AA, and translated into a regulatory equity target ratio (close to GAAP) of 57.46%. The difference (5.46%) represents equity that has been added to offset imputed debt associated with purchase power and operating lease commitments.[74]

[73] Lee Huffman, *Recommended Decision of the Hearing Examiner*, NMURC Case No. 06-00340-UT, Nov. 29, 2007, p. 20.

[74] PSC of Wisconsin, *Final Decision*, 6690-UR-118, January 15, 2008.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-09-03

IDAHO POWER COMPANY

SMITH, DI
TESTIMONY

EXHIBIT NO. 7

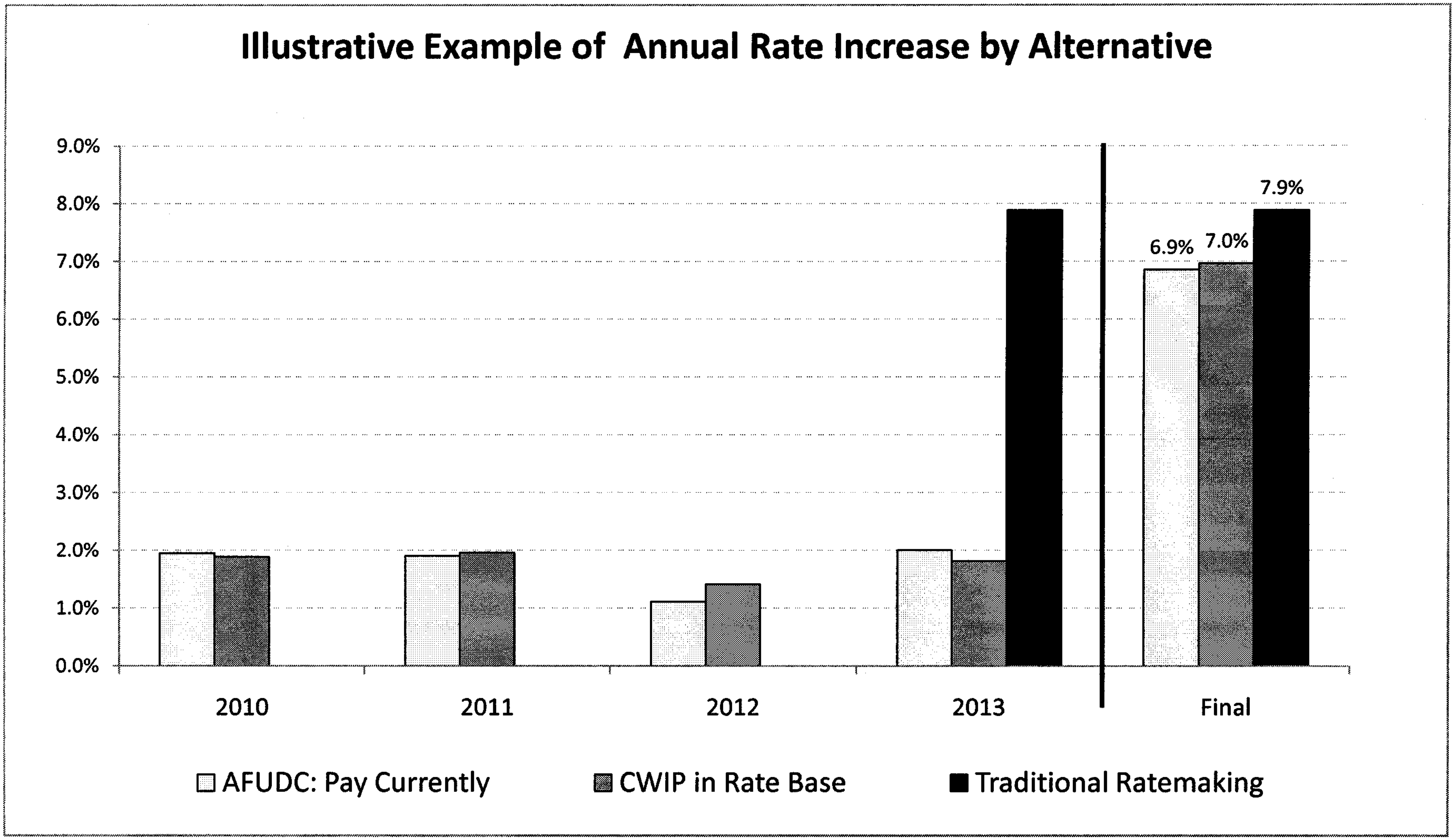

Exhibit No. 7
Case No. IPC-E-09-03
L. Smith, IPC