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May 31, 2007

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket No. UM 1276

Enclosed for filing in the above-referenced proceeding are the Opening Comments of PacifiCorp. A copy of this filing has been served on all parties to this proceeding as indicated on the attached service list.

Very truly yours,

Katherine A. McDowell

Enclosure
cc: Service List

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**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 1276

In the Matter of THE PUBLIC UTILITY COMMISSION OF OREGON Staff's request to open an investigation regarding performance-based ratemaking mechanisms to address potential build-vs.-buy bias.	**OPENING COMMENTS OF PACIFICORP**

I. INTRODUCTION

As summarized in the caption to this docket, the objective of this investigation is to develop PBR-type incentives or other regulatory innovations to lessen or eliminate perceived utility preference for utility-owned resources over purchased power resources. Through the workshops leading up to these Opening Comments, the parties to this case have produced a series of straw proposals addressing this issue. With input from other parties, PacifiCorp developed the Conservation Incentive Model for purchased power ("CIM/pp"), a copy of which is attached to these Opening Comments as Exhibit 1.

In reviewing these straw proposals, the Commission should consider at least three aspects of the larger context of this case.

First, this docket is the last of a trilogy of major policy investigations at the Commission on resource planning and acquisition, including UM 1182, which updated the Commission's guidelines for competitive bidding, and UM 1056, which updated the Commission's guidelines for resource planning. *See In re Investigation Regarding Competitive Bidding*, Order No. 06-446, UM 1182 (2006); *In re Investigation into Integrated Resource Planning Requirements*, Order No. 07-022, UM 1056 (2007). These

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investigations were activities specifically designed to promote one of the Commission's principal agency objectives since 2005, which is to "Adopt regulatory policies that encourage utilities and customers to meet energy needs at the lowest possible cost and risk."[1] The Commission should judge the straw proposals in this case by whether they complement the resource planning and acquisition policies adopted in UM 1182 and UM 1056.

Second, this docket effectively constitutes the last phase of a review of the Commission's policy on the pricing of new generation resources which began in AR 417/AR 441 and has continued in UM 1066. This "cost or market" issue was raised by the enactment of direct access in Oregon in 1999 through ORS 757.600, et seq. As direct access was originally envisioned, utilities were to provide a market-based standard offer rate as the default rate, but not a cost-of-service rate. To implement direct access, the Commission adopted a rule, OAR 860-038-0080(1)(b), providing that: (1) utilities were not required to add new generation resources; (2) major capital improvements to existing resources were subject to an IRP process; and (3) new generating resources were included in revenue requirement at market prices, not at cost, and not added to rate base even if owned by the utility.

In the wake of the Western energy crisis in 2001, however, Oregon amended its direct access law to require utilities to provide a cost-of-service rate to all customers unless the Commission waived this requirement based upon specific findings regarding the functionality of the competitive retail market. ORS 757.603. Since the enactment of ORS 757.603, the repeal of OAR 860-038-0080(1)(b) has been the subject of considerable debate. In its direct access rulemaking, AR 417/AR 441, the Commission declined to decide whether to repeal the rule and instead opened an investigation on the issue, UM 1066.

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[1] *See* http://www.puc.state.or.us/PUC/commission /2005_objectives.shtml.

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In March 2005, the Commission abated UM 1066, based upon the following rationale:

> "The comments submitted provide numerous valid reasons for including new generating resources in a utility's revenue requirement at cost, rather than at market price. We are still concerned, however, that the use of a cost standard will cause a utility to favor its own proposed resources. Two of our open dockets are intended to address the incentive and ability of a utility to favor its own projects. One docket, UM 1182, will revise the competitive bidding guidelines to ensure resources are considered on an equal basis. The other docket, UM 1056, will modify the least-cost planning requirements to foster a timely, efficient acquisition of new resources. Finally, we intend to open an additional investigation docket later this year to consider the use of performance-based ratemaking to offset utility bias in favor of owning its own resources. We want to wait until those proceedings are resolved to issue our final decision in this docket."

In re Investigation Into Regulatory Policies Affecting New Resource Development, Order No. 05-133, UM 1066 (2005).

The Commission should test the straw proposals in this docket by whether they are sufficiently robust to address and eliminate the impediments to final modification of OAR 860-038-0080(1)(b). *See* Staff Report, UM 1276 (Item No. 1, August 22, 2006 Public Meeting) (August 14, 2006) ("Staff Report") ("Going forward with this investigation will bring docket UM 1066 to final resolution."). PacifiCorp submits that modification of OAR 860-038-0080(1)(b) is necessary to rationalize the Commission's architecture for new resource planning and acquisition adopted in UM 1182 and UM 1056. Indeed, assumptions around the continued inclusion of new resources in a utility's rate base at cost are contained in the final orders in both UM 1182 and UM 1056, and are a premise of this investigation.

Third, the Commission should review the straw proposals in this case for consistency with key Commission precedents. This is the second investigation the Commission has conducted on the "build vs. buy" issue. The first was UM 573, opened in response to the passage of the Energy Policy Act of 1992. *See In re Requirements of Section 712 of the*

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1992 Energy Policy Act, Order No. 93-1491, UM 573 (1993); *see also In re Requirements of Section 712 of the 1992 Energy Policy Act*, Order No. 94-1611 (1994). In this investigation, the Commission was one of the first to acknowledge the potential impacts of PPA-related imputed debt on a utility's balance sheet.

This is also the second major docket on incentive regulation, the first being UM 409, where the Commission adopted incentives for conservation. *See In re Electric Utility Incentives for Acquisition of Conservation Resources*, UM 409, Order No. 92-1673 (1992); *see also In re PacifiCorp and PGE Conservation Program Expenses*, Order No. 89-1700 (1989). Because of these cases, the Commission does not need to start from scratch in this case, but instead can build from the results of its earlier investigations.

II. COMMENTS ON CONSERVATION INCENTIVE MODEL FOR PURCHASED POWER

Mindful of the point just made—that the Commission should use its existing precedents as building blocks for this investigation—the Conservation Incentive Model for purchased power (CIM/pp) takes Oregon's historic approach to neutralizing utility bias against conservation and applies it to neutralizing perceived utility bias against purchased power. The premise of this approach is to develop regulatory comparability between the desired resource (conservation or purchased power) and utility-owned resources, and provide an opportunity for additional, utility-specific incentives.

The CIM/pp has two major components. The first is based on *In re PacifiCorp and PGE Conservation Program Expenses*, Order No. 89-1700 (1989), where the Commission allowed capitalization of all DSM expenditures (both capital and expense) to remove the disincentive to invest in new DSM. The Commission also allowed amortization of these costs, with a return, over the life of the DSM program.

The CIM/pp tracks this approach by allowing utilities to capitalize certain PPA costs, with an AFUDC-type return before these costs are reflected in rates. Thereafter, assuming the Commission finds that the PPA is prudent, the utility amortizes the capitalized PPA costs

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over the life of the PPA, with a return based on the utility's ROR. Because the prudence review of a PPA can occur in the context of a RVM or PCAM filing (mechanisms now in place for PGE and PacifiCorp), regulatory lag should be a manageable factor in the implementation of this proposal.

While the CIM/pp follows the capitalization concept developed in Order No. 89-1700, it tailors this concept in several ways to fit its application to purchased power.

First, to accomplish the Commission's policy objective in this docket, the CIM/pp is broadly designed to cover any PPA that could be replaced by a utility-owned asset. To exclude a large volume of short-term transactions, however, the CIM/pp is limited to new, multi-year PPAs.

Second, the CIM/pp applies only to the capacity portion of PPAs (if not specified in the contract, the proxy capacity value is determined using S&P's methodology). The capacity portion is also capped at a maximum of 50 percent of total PPA costs. Limiting the capitalization to capacity costs makes the CIM/pp more practical to implement and more modest in scope. It is also designed to help counteract rating agency debt imputation for PPAs, which targets PPA capacity costs.

Third, the CIM/pp determines the amount to be capitalized by applying a net present value analysis to PPA capacity costs, using the same discount rate S&P uses in its debt imputation methodology (*i.e.,* the utility's average cost of debt over 3 years).

The other major component of the CIM/pp is based on *In re Electric Utility Incentives for Acquisition of Conservation Resources*, UM 409, Order No. 92-1673 (1992). In this case, the Commission acknowledged that regulatory comparability was insufficient to change utility behavior because this, at best, left utilities indifferent. Thus, the Commission also allowed utilities to seek additional incentives to make DSM expenditures more attractive than traditional supply-side investment. The Commission decided that these incentive

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mechanisms should be, at least to some degree, utility specific because a mechanism can only function as an incentive if the entity sought to be encouraged views it as such.

The Commission gave five specific policy goals for these additional incentive mechanisms: (1) symmetrical rewards and penalties; (2) specific benchmarks; (3) proportionate rewards/penalties; (4) significant but not excessive incentives; and (5) savings should be based on best estimates and not subject to after-the-fact true-up adjustments.

The CIM/pp allows utilities to propose additional, utility-specific incentives for PPAs, as long as they meet the policy goals set forth in UM 409.

As demonstrated by the CIM/pp, the Commission's conservation incentive precedents provide a useful framework for the development of purchased power incentives in this docket. The framework has the key virtue of being predictable in its application across a wide variety of different types of PPAs, a necessary component of any effective incentive mechanism. The limitations proposed by the CIM/pp, particularly its application to PPA capacity costs only, make the CIM/pp workable and adhere to the Commission's policy against excessive incentives. The approach of capitalizing PPA costs, subject to a prudence review, specifically tracks one of the suggestions in the Staff Report for "controlling the incentives provided to the utilities while allowing a return on all or a portion of the PPA contract." Staff Report at 7.

An example of a similar approach to the CIM/pp is Mississippi Section 77-3-93, which entitles a utility to a return on the capacity portion of a PPA from a non-utility generator which is more than 30 days in duration, subject to a reasonableness review by the Commission.

PacifiCorp appreciates PGE's related straw proposals, providing an income opportunity on contracts and on a PPA portfolio. PacifiCorp has two concerns about these proposals, however, as compared to the CIM/pp. With respect to the straw proposal proposing an income opportunity for contracts, the concept of variable return rates for

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different contract types could lead to uncertainty and potential conflict among parties over the proper return rate. With respect to PGE's straw proposal for an income opportunity by portfolio, the issue is whether the application of the incentive to the entire PPA portfolio might dilute the impact of the incentive on future resource decisions.

III. COMMENTS ON PGE'S DEBT IMPUTATION STRAW PROPOSAL

The topicality and importance of this docket was underlined in December 2006, when S&P asked for comments on a proposal to refine its guidelines on imputed debt associated with purchased power. These new guidelines, adopted in the first quarter of 2007, generally expand the range of PPAs to which S&P will impute debt by eliminating the previous 3-year minimum and introducing the concept of "evergreening," which assumes short-term PPAs will be renewed to meet long-term obligations to serve load.

S&P published its first guidelines on debt imputation in 1990 and updated them in 1993 after the passage of EPACT 1992. In the Commission's first "build vs. buy" docket, the Commission acknowledged that "a utility's capital structure may be influenced by long-term purchased power obligations." *In re Requirements of Section 712 of EPACT 1992*, Order No. 94-1611, UM 573 (1994).

The issue next resurfaced after S&P reworked its debt imputation guidelines in 2002-03 to address the growing number of PPAs, especially tolling agreements. These guidelines resulted in increased amounts of imputed debt for Oregon utilities. For example, in a recent presentation, S&P cited PacifiCorp as an example of a utility with a relatively large amount of imputed debt, changing the debt to total capital ratio by 6.4 percent, from 52.6 percent to 59 percent. *See Debt Imputation for Power Purchases: Standard & Poor's Revised Approach* at 13 (Feb 23, 2007), attached as Exhibit 2.

Because the existence of imputed debt associated with PPAs is irrefutable, the Commission must address this issue to achieve its policy objectives in this docket. S&P has

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made clear that there are two ways in which commissions can respond. *See* Summary of Phone Call with David Bodek of S&P from UM 1276 Workshop, attached as Exhibit 3.

First, commissions can adopt regulatory mechanisms that reduce the baseline risk factor of 50 percent used in the debt imputation calculation. This does not eliminate or offset imputed debt, but may lower the overall level of debt. Unfortunately, based upon the workshop discussions focusing on this issue, the Commission's ability to materially alter current imputed debt levels for Oregon utilities through regulatory recovery mechanisms appears quite limited. *Id.* For example, PGE reported that it has a 30 percent risk factor, which is close to the 25 percent maximum reduction S&P allows absent a legislative mandate. For this reason, no party has sponsored a straw proposal specifically designed to reduce the risk factor through new power cost recovery mechanisms.

Second, commissions can recognize a revenue stream to offset the impacts of the imputed debt, either by adoption of a proposal such as the CIM/pp or by adoption of an approach such as that presented in PGE's straw proposal to impute additional equity in the utility's capital structure. Staff's Report specifically acknowledged equity offsets as an option for addressing imputed debt:

> "S&P has identified an authorization of return on the amount of additional common equity needed to offset the debt equivalency of a PPA as one method regulators can used to recognize the cost of debt equivalency. Simply put, recognizing the imputed debt from the PPA will cause a utility's debt-equity ratio to change. The common equity offset would be an addition to the common equity that would restore the authorized debt-equity ratio to the approved ratio. The effect of this addition would be a slight upward movement in the overall authorized rate of return."

Staff Report at 6.

Other states have instituted equity offsets similar to those contained in PGE's straw proposal on debt imputation. Florida has allowed rate recovery for equity designed to offset imputed debt costs associated with QF contracts. *See In re Florida Power & Light*, Florida

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Public Service Commission, Order Nos. PSC-99-0519-AS-EI; PSC-02-0501-AS-E1. Colorado recognized higher equity in a utility's capital structure infused to offset debt. *See In re Public Service Co of Colorado*, Colorado Public Utilities Commission, Dockets 04A-214E, 04-215E and 04A216E. Also, some states have also expressly included the impact of debt imputation on cost of capital in their RPS cost recovery language, such as Nevada. *See* NRS 704.7821(7)(b).

If the Commission does not adopt the CIM/pp, then it should adopt PGE's straw proposal on imputed debt. PacifiCorp suggests that the Commission approve the general concept of an equity offset to imputed debt and permit utilities to modify the exact details of PGE's straw proposal regarding calculation of the equity offset as necessary to suit their individual circumstances.

IV. COMMENTS ON NIPPC'S STRAW PROPOSAL

NIPPC's straw proposal addresses the "build vs. buy" issue in both the Request for Proposals (RFP) and ratemaking context. On the ratemaking issue, NIPPC generally supports the CIM/pp, a position that PacifiCorp appreciates.

On the RFP issue, NIPPC asks the Commission to reopen its UM 1182 order, change the approach to resource comparability adopted in RFP Guidelines 9 and 10 of that Order, and impose a new "PPA risk avoidance discount." As discussed above, PacifiCorp believes that parties should work from the decisions in UM 1182 and UM 1056, not reargue them. Separate proposals on resource planning and acquisition are outside of the scope of this investigation on ratemaking incentives.

Additionally, Oregon RFP Guidelines 9 and 10 adopted in UM 1182 direct consideration of non-price factors such as those sought to be quantified in NIPPC's proposal in bid evaluation and require an independent evaluator to score a utility self-build option taking into account these same non-price risks. *See In re Investigation Regarding Competitive Bidding*, Order No. 06-446 at 10-13. UM 1182 (2006). Because the current

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RFP guidelines require review of risks and benefits of different resources, there is no clear need for NIPPC's PPA risk avoidance discount in the RFP process, especially when the concept would be so challenging to fairly design and implement.

Quantification of the value of risk assumption in a PPA is a complex exercise, in part because this value varies by contract types and terms. An across-the-board discount for PPAs of 10 percent does not account for the wide variability of contracts or for the offsetting risks that PPAs can create. In the earlier "build vs. buy" docket in Oregon, the Commission compiled a list of the advantages and disadvantages of utility and non-utility ownership of a resource. *See In re Requirements of Section 712 of the 1992 Energy Policy Act*, Order No. 94-1611 at Appendix 2, UM 573 (1994). A review of this list shows how difficult it would be to establish that PPAs should be discounted and to set the level of this discount.

In the place of this proposal, and building on NIPPC's support for the CIM/pp, the Commission could consider excluding the costs of the incentives provided by the CIM/pp from the economic analysis of bids in an RFP. In this manner, PPAs would not be disadvantaged in the RFP process by the CIM/pp. This approach is similar to the Commission's approach to imputed debt costs in the RFP process. As a policy matter, Guideline 9 precludes consideration of these costs in determining the initial short-list, even if this may give an advantage to PPA bids. *Id.* at 12. The Commission could extend similar treatment to CIM/pp incentive costs and potentially obviate the need for NIPPC's straw proposal.

NIPPC suggests that the Commission review the regulatory construct that emerges from this docket after 5 years to ensure its effectiveness. PacifiCorp supports this proposal.

V. COMMENTS ON ICNU's ROE DISCOUNT PROPOSAL

ICNU's straw proposal is designed to offset any economic value provided to the utility under a PPA incentive mechanism by a reduction in the utility's Return on Equity (ROE). ICNU's proposal is most accurately viewed as an anti-proposal, because such an

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equity reduction would effectively negate the purpose and effect of any incentive mechanism the Commission adopts. Indeed, by creating additional balance sheet risk to utilities, ICNU's proposal is worst than circular, likely leaving utilities in a more negative position financially from acquiring PPAs than they would have been without an incentive mechanism in the first place. For this reason, PacifiCorp would not seek a PPA incentive mechanism if it was conditioned on ICNU's proposed equity reduction.

In addition, ICNU's straw proposal lacks foundation in sound regulatory principles. ICNU's bases its straw proposal on the theory that the incremental revenues produced by a PPA incentive mechanism reduce the utility's overall risk. But, the point of the mechanisms proposed in this case is to offset the additional financial risk that PPAs create for utilities in the form of imputed debt and lowered returns. *See, e.g.*, Rosenberg, *Purchased Power: Risk Without Return?*, 134 Pub Util Fort 36 (1996) (summarizing the financial, regulatory and supply risks that justify regulators treating PPAs as a capital asset with a return on investment). The incentive mechanisms are therefore not risk reducing; they are risk neutralizing. Even if ICNU's theory was that the acquisition of additional PPAs should lower the utility's overall risk (a variation on NIPPC's theory), as discussed above, PPA risk assumption is contract specific, difficult to quantify, and potentially offset by the additional risks that PPAs present.

PacifiCorp appreciates ICNU's underlying concern about the potential costs of a PPA incentive mechanism, and PacifiCorp designed the CIM/pp with this in mind. But, unless an incentive mechanism provides material economic value to the utility, it will not function as an incentive. The CIM/pp attempts to balance these two competing concepts. Ultimately, customers will benefit from a balanced, well-designed incentive mechanism through the

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acquisition of additional, cost-effective PPAs and the future resource optionality a robust wholesale market provides.

DATED: May 31, 2007.

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UM 1276 on the following named person(s) on the date indicated below by email and first-class mail addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: May 31, 2007.

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Of Attorneys for PacifiCorp

EXHIBIT 1

Incentives for New PPAs Based Upon Oregon Conservation Incentive Model CIM/pp (Conservation Incentive Model for purchased power)

Concept: Incent Oregon utility acquisition of new PPAs by applying Oregon's model for conservation incentives, treating PPA capacity costs similarly to DSM costs.

Background: The Commission issued a series of orders in the late 1980's and early 1990's designed to encourage utility DSM expenditures by allowing comparable rate treatment for supply-side and demand-side costs. The goal of PPA incentives is similar, in that they are designed to allow comparable regulatory treatment of two types of supply-side resources.

To remove the disincentive to invest in new DSM, the Commission allowed capitalization of all DSM expenditures (both capital and expense). The Commission also allowed amortization of these costs, with a return, over the life of the DSM program. *See In re PacifiCorp and PGE Conservation Program Expenses*, Order No. 89-1700 (1989). In this manner, the Commission established comparability between utility expenditures in DSM and utility investment in new generation plant.

The Commission recognized, however, that eliminating the disincentive to invest in DSM was insufficient to change utility behavior because this, at best, left utilities indifferent. Thus, the Commission also allowed utilities to seek additional incentives to make DSM expenditures more attractive than traditional supply-side investment. The Commission decided that these incentive mechanisms should be, at least to some degree, utility specific because a mechanism can only function as an incentive if the entity sought to be encouraged views it as such.

The Commission gave five specific policy goals for these additional incentive mechanisms: (1) symmetrical rewards and penalties; (2) specific benchmarks; (3) proportionate rewards/penalties; (4) significant but not excessive incentives; and (5) savings should be based on best estimates and not subject to after-the-fact true-up adjustments. *In re Electric Utility Incentives for Acquisition of Conservation Resources*, UM 409, Order No. 92-1673 (1992).

Proposal:

- Allow utilities to capitalize expenditures in capacity portion of new PPAs of one-year or longer in duration. Utilities should derive the capitalized amount by determining the net present value (NPV) of PPA capacity payments from contract inception through termination. Utilities should use the same NPV calculation that S&P now uses in imputing debt related to PPAs, which applies a discount rate based on the utility's average cost of debt.

- Where a PPA does not have an identifiable capacity component, use the current S&P method for determining a proxy capacity component. In any event, the capacity portion of a PPA shall be capped at 50% of the total PPA costs.

- Recognize AFPPA (Allowance for Funds used for PPAs), using the utility's AFUDC rate calculated on a post-tax basis, for capitalized portion of new PPAs before costs are reflected in rates.

- In rate case or annual net variable power cost update, allow utilities to amortize prudent PPA capacity expenditures, plus AFPPA for capacity portion of PPA, over life of PPA.

- Allow utilities to earn return on amortization of capacity portion of PPA at utility's allowed ROR, calculated on a pre-tax basis.

- PPAs are subject to a prudence review before amortization of capitalized capacity payments in rates.

- Allow utilities to propose additional utility-specific PBR mechanisms for PPAs using policy goals for incentive mechanisms from UM 409. This could incorporate other proposals developed in this docket.

Benefits: The CIM/pp benefits customers by encouraging utilities to more aggressively acquire cost-effective PPAs. Utility acquisition of new PPAs contributes to the development and maintenance of a robust competitive wholesale market, which ultimately provides customers greater resource optionality.

The CIM/pp is limited in scope in that it only applies to: (1) new PPAs; (2) PPAs of one year or more in duration; and (3) the capacity portion of PPAs, which is capped to prevent cost-shifting to capacity in PPAs. These limitations moderate the rate impact of the CIM/pp. At the same time, CIM/pp should be effective in reducing future imputed debt and associated costs because S&P imputes debt only on the capacity portion of PPAs. From a qualitative standpoint, the CIM/pp should also help enhance the credit quality of Oregon utilities and lower overall costs of capital for new utility investment.

Under the CIM/pp, PPA costs will not be reflected in rates until a prudence review is conducted. Thus, the CIM/pp maintains the regulatory discipline of the risk of a prudence disallowance.

This approach uses a tried and tested framework to incent Oregon utilities to invest in alternatives to rate base generation resources. The CIM/pp is straightforward, easily implemented for all utilities, and allows for utility-specific tailoring of incentives beyond those designed to treat PPAs and rate base generation comparably for regulatory purposes.

EXHIBIT 2

STANDARD
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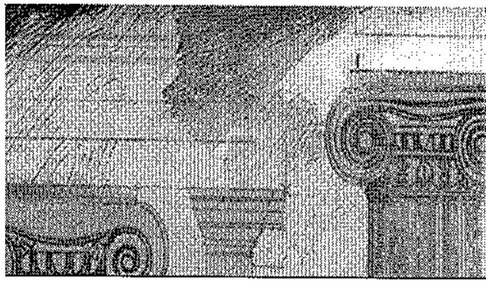
Debt Imputation for Power Purchases: Standard & Poor's Revised Approach

Utility Rate Case: Issues and Strategies, LSI Conference February 23, 2007

Anne Selting, Director
Utilities, Energy & Project Finance Ratings

The McGraw-Hill Companies



Outline of Presentation

- Why does Standard & Poor's make adjustments to utilities' financial statements for power purchase agreements (PPAs)?
- What adjustments are made?
- A numerical example
- Changes in our methodology
- Questions

STANDARD
&POOR'S

What Is the Logic Behind Debt Imputation?

The McGraw-Hill Companies

Regulated Utilities that Enter PPAs Face Risks and Benefits

BENEFITS

- ✓ No construction risk
- ✓ When properly structured, operating risk is transferred to another party
- ✓ Reduces cost variability
- ✓ In some cases, recovery is more straightforward than when building plant

RISKS

- ✓ Increased financial risk
- ✓ Increased liquidity requirements
- ✓ Ultimate recovery of obligation in retail electric rates

Debt Imputation Captures the Risks of PPAs in a Utility's Financial Metrics

- PPAs imply fixed obligations for a utility that typically consist of the capacity payments made to the supplier
- Standard & Poor's imputes a debt equivalent that is based on this fixed obligation
- The goal is to reflect in our financial metrics the credit exposure a utility has when it enters a PPA
- Comparability of financial commitments across regulated utilities is achieved
  - Without adjustments, a utility that builds generation to meet requirements reflects 100% of generation debt on the company balance sheet

But…

  - A utility that exclusively purchases its requirements has an obligation which is not reflected on its balance sheet

Current Approach

- Take the net present value (NPV) of capacity payments
  - The discount rate reflects each utility's average cost of debt
  - NPV calculation is applied from contract inception through termination
- A "risk factor" adjustment is made to the result, typically between 0% - 50%, reducing the obligation
- This number is then added to the utility's off-balance sheet debt; adjustments made to cash flow metrics too
- An interest expense is also imputed
- Increases a company's debt burden and interest expense, typically weakens overall capital structure
- Approach is consistent with logic that PPAs are a financial obligation

STANDARD
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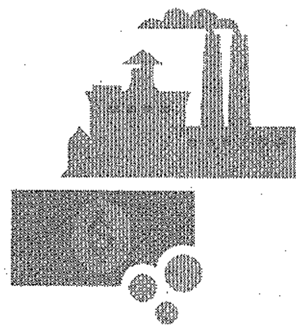
A Numerical Example

The McGraw-Hill Companies

12-Year PPA, Utility Recovers Costs in a Fuel Adjustment Clause (FAC)



1. Review PPA Terms

Year	$m
1	500
2	500
3	500
4	500
5	500
Thereafter	4,000
Total	$6,500

2. Isolate fixed capacity per year

NPV@ 6.5%
= $4,079

3. Calculate NPV using utility's average cost of debt over last 3 years

25% * $4,079 =
$1,020

4. Multiply by risk factor between 0% - 50%

What is a Risk Factor and Why Is It Used?

- A key risk that a regulated utility has is when and how much of the fixed commitment that a PPA represents will ultimately be recovered in retail electric rates
- This depends on the regulatory environment and the mechanisms in place for recovery
- We incorporate a "risk factor" that attempts to measure the level of risk of recovery by jurisdiction
- All risk factors adjust downward the PPA off-balance sheet debt, relative to not using a risk factor
- This reflects our view that utilities have a strong history of being able to recover PPA costs
- Assigning a risk factor distinguishes different levels of regulatory risk

Under New Criteria Our Guidelines for Determining Risk Factors

- ✓ 50% Risk Factor – Utility passes capacity payments through in base rates
- ✓ 25% Risk Factor – Utility passes capacity payments through in a fuel clause adjuster
- ✓ 0% - 20% Risk Factor – Utilities have legislative authority to pass through costs

Using Results to Adjust S&P Ratios

	Year 1	Year 2	Year 3	Year 4	Year 5	...	Year 12
Funds from operations	2,500						
Interest expense	650						
Directly issued debt	10,000						
Shareholder equity	9,000						
Fixed capacity commitments	500	500	500	500	500	...	500

NPV of fixed capacity payments	$4,079	@ 6.5% discount rate
Applying 25% risk factor	$1,020	=$1,020 * 0.25
Imputed interest	$66	=$1,020 * 6.5%
Depreciation expense	$59	=($500 * 0.25) - $66

S&P Credit Metrics - Without PPA Adjustments

FFO/interest x	4.8	= 2,500 + 650 / 650
FFO/total debt (%)	25%	= 2,500 / 10,000
Debt/Capitalization (%)	53%	=10,000 / 10,000 + 9,000

S&P Credit Metrics - With S&P PPA Adjustments

FFO/interest x	4.6	= 2,500 + 650 + 66 + 59/ (650 + 66)
FFO/total debt (%)	23%	= 2,500 + 59 / 10,000 + 1,020
Debt/Capitalization (%)	55%	=10,000 + 1,020 / 10,000 + 9,000 + 1,020

Comparing Results for Total Debt to Capitalization

TD/TC

Business Profile	AA Category		A Category		BBB Category		BB Category	
1	48.0	55.0	55.0	60.0	60.0	70.0		
2	45.0	52.0	52.0	58.0	58.0	68.0		
3	42.0	50.0	50.0	55.0	55.0	65.0	65.0	70.0
4	38.0	45.0	45.0	52.0	52.0	62.0	62.0	68.0
5	35.0	42.0	42.0	50.0	50.0	60.0	60.0	65.0
6	32.0	40.0	40.0	48.0	48.0	58.0	58.0	62.0
7	30.0	38.0	38.0	45.0	45.0	55.0	55.0	60.0
8	25.0	35.0	35.0	42.0	42.0	52.0	52.0	58.0
9			32.0	40.0	40.0	50.0	50.0	55.0
10			25.0	35.0	35.0	48.0	48.0	52.0

53% closer to BBB+, 55% closer to BBB-

Actual Examples (Not Yet Revised to Reflect Changes to Methodology)

	Pinnacle West Capital Corp.	PacifiCorp	Nevada Power Co.¶	Tucson Electric Power Co.	PNM Resources Inc
Rating as of Feb. 22, 2007	BBB-/Stable/A-3	A-/Stable/A-1	BB-/Stable/NR	BB/Stable/B-2	BBB/Negative/A-3
	--Fiscal year ended Dec. 31, 2005--	--Fiscal year ended March 31, 2006--	--Fiscal year ended Dec. 31, 2005--	--Fiscal year ended Dec. 31, 2005--	--Fiscal year ended Dec. 31, 2005--
(Mil. $)					
Debt/total capital (%)	49.1	52.6	55.8	72.7	61.9
Adusted Debt/total capital (%)	57.5	59.0	58.6	74.7	65.9
Difference	8.4	6.4	2.8	2.0	4.0

Adjustments include PPA debt, Pension debt, Operating leases.

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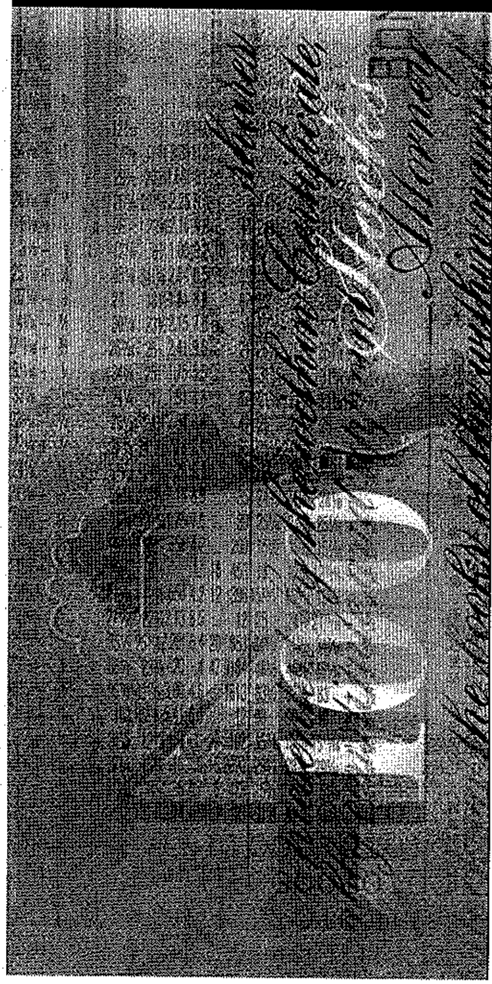

Recent and Contemplated Changes to Our Methodology

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Standard & Poor's Has Modestly Revised Its Methodology

Issue	Historic Approach	Revised Approach
Contract life	All contracts > 3 years	All contracts regardless of length
Interest rate	Standard 10%	Utility's average cost of debt over 3 yrs
Risk factor	*-10-20%: legislative mandate*	*-0%-20% legislative mandate*
	-50% base rate recovery	*-no change*
	-30% fuel adj clause recovery	*-25% fuel adj clause recovery*
Depreciation adjustmnt	None	Added to FFO/int & FFO/TD
Evergreening	Not done	Under consideration
Energy only contracts	50% of PPA costs if no capacity pymt	Proxy $/kW based on CT

Different Contract Length Leads to Evergreen Considerations

	No Evergreening of Contracts									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Utility X	100	100	100	100	100					
NPV X @6.5%	$ 416									
Utility Y	100	100	100	100	100	100	100	100	100	100
NPV Y @ 6.5%	$ 719									

	With Evergreening of Contracts									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Utility X	100	100	100	100	100	100	100	100	100	100
NPV X @6.5%	$ 719									

$\underbrace{\text{Year 6 – Year 10}}_{\text{“Evergreening”}}$

Why Are We Considering "Evergreening"?

- PPA debt imputation stems from the need to make meaningful comparisons between utilities that build versus buy
- But comparisons between utilities that buy also exist when the contract lives are significantly different
- For utilities that have an obligation to serve, a short-term contract does not fully capture what is effectively a near-term solution to a long-term, ongoing obligation
- For this reason, extending an existing short-term contract beyond its actual termination date is under consideration, unless self build is clearly occurring

What About Renewable Energy PPAs?

- Renewable PPAs also constitute an obligation that Standard & Poor's will capture under its debt imputation methodology
  - As with a "conventional" PPA, the utility is making a decision to purchase rather than build capacity
  - Conceptually, logic for imputing renewable PPAs is no different
- Unlike traditional PPAs, there is often no defined capacity payment
  - Wind energy is typically "as available" with developer taking on output risk
  - Other generation with very low variable costs also may be energy only
- Proposed to take proxy capacity charge, based on marginal costs of new CT $/kw-yr * kw under PPA.
- As a theoretical matter, several defensible approaches could be taken

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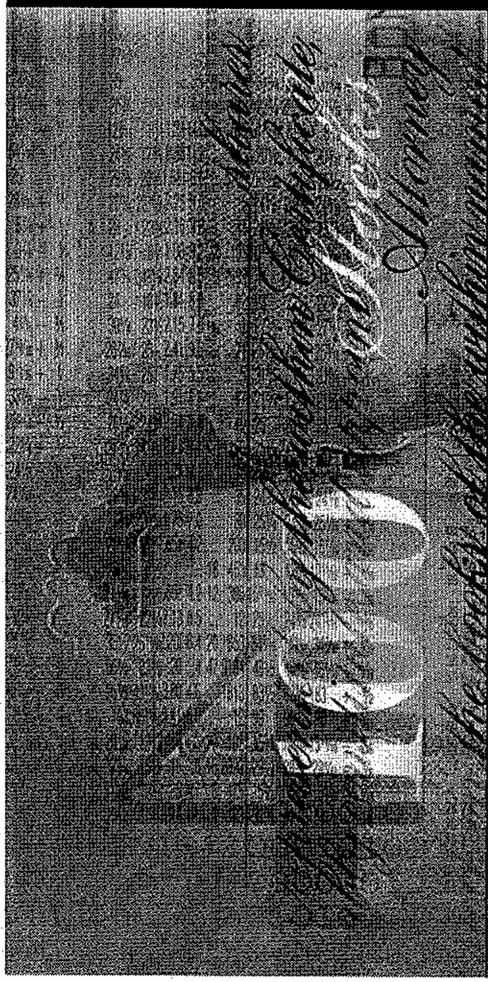

QUESTIONS??

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The McGraw-Hill Companies

EXHIBIT 3

Phone call with David Bodek-S&P during UM 1276 workshop 3/16/07

General Background:

- S&P wants to identify obligations with debt-like attributes. They look at fixed obligations/capacity payments. They then reduce (because they recognize recovery methods) that obligation by a risk factor percentage.
- S&P has no bias – neutral to build-vs-buy.
- S&P does want a degree of comparability between companies who build versus companies who buy, so they adjust the financial metrics (more discussion on this below) for those who buy.

Current methodology:

- S&P views contracting for PPAs as a replacement for building plants to put into rate base. S&P wants to capture the debt that would otherwise be used for building a plant. This is the reason they only impute debt on the capacity portion of the contracts.

- PCAs reduce debt imputation and the risk factor.

- To offset imputation, S&P looks to the utility to issue equity or for commissions to impute equity.

Proposed methodology:

- S&P will look at utilities entering into short-term contracts (3 years or less) used to meet long-term obligations. S&P is trying to reconcile this with utilities meeting their obligations through building.

Questions List

1. **Is there a minimum contract size S&P considers for purposes of debt imputation? Does this vary by type of PPA?**

   S&P would rather look at a portfolio of contracts and may not consider "gap filler" contracts in that portfolio. There is no "bright-line" test. They look at the gap between reported ratios and adjusted ratios and are only concerned and consider the weighting of the adjustment if there is a significant change between the two sets of ratios.

2. **If a regulator provides "phantom equity" in the regulatory process to offset debt imputation, does S&P give credit for this equity in establishing ratings?**

   Yes, S&P would give credit for imputed equity such that it simply improves a utility's credit metrics/ratios used as a factor in ratings and that it strengthens credit quality. The imputed equity affects cash flow, interest coverage, FFO/Debt, etc. The regulator has two options 1) increase rate of return or 2) impute equity for ratemaking.

Is there an effect on capital structure?

David did not think it would affect capital structure, but he is checking. Regulators could give a higher rate of return or impute equity (which would give a better cash flow). S&P would recognize an enhanced revenue stream.

3. **If "phantom equity" is not provided for in the regulatory process, could the utility carry higher equity in its capital structure to offset the impact of PPA debt imputation?**

   If the regulator does not impute equity, the offset of the utility carrying higher equity levels depends on the authorized capital structure by the commission. In addition, the ability of the utility to actually issue equity substantial enough to offset the debt equivalence could be constrained by the regulator. However, S&P recognizes that any increase in equity to offset the debt imputation is "good."

4. **Does S&P impute debt as of the time a PPA is signed or when the contract takes effect?**

   As long as no payments are made prior to the beginning of the contract, it is not considered until the contract takes effect- there is no NPV backdating (distinguished from building, where debt is incurred prior to building completion).

5. **Does S&P treat PPAs for qualifying facilities (QFs) differently than other PPAs for purposes of debt imputation?**

   QFs are treated the same as other contracts. The risk factor is the same.

6. **When does S&P intend to finalize and begin application of its revised debt imputation policy?**

   No commitment. S&P is "working feverishly;" potentially by the first quarter end.

   David did not want to discuss new methodology but the following points were made:

   - Will abandon the 3 year rule,
   - Business risk: increasing short-term contacts leads to increased volatility, which leads to increased risk, which leads to the utility needing to show stronger financial metrics,
   - No distinction between bi-lateral and structured markets,
   - Spot purchases: depends on the company if S&P will include them. They will ask questions to determine the risk and volatility as well as consider the regulatory environment and qualitative and quantitative factors,

- Capacity Contracts: will have to think about whether those will be treated any differently.

7. **Under the revised policy, is there any minimum contract length for debt imputation? Will all types of short-term PPAs be considered for debt imputation?**

   There is no minimum contract length. For the most part, all short-term contracts will be included under the new methodology. However, there may be some "carve-outs" like short-term contracts that are just used as gap fillers for long-term contracts or for a plant to come on-line. PPA has an advantage over debt as PPA has a recovery (where debt is 100% risk) and is factored in a lower rate.

8. **Why is S&P proposing to change the risk factor percentages? Is the effect of the proposed changes to the risk factor percentages to give legislatures and commissions a greater ability to minimize imputed debt from PPAs?**

   Risk factors are reduced when there is an effective PCA mechanism. David reminded the group that imputed debt is still less than debt in the capital structure that is actually used to build – that is 100% debt, where imputed debt from contracts is "ratcheted down" by the associated risk factor.

9. **What changes is S&P proposing to the discount rate used in the calculation of the net present value of capacity payments in a PPA? Specifically, please explain the methodology S&P will use to calculate a utility's average cost of debt over 3 years. Also, if this change lowers the amount of debt imputed, how would this change in the amount of debt then impact the resulting imputed interest that is assessed for coverage ratios?**

   Historically, S&P arbitrarily used a 10% discount rate. That was later changed to using a specific utility's average cost of debt (with some adjustments) of the average debt balances from the prior and current year. Under the new methodology, S&P is proposing to segregate taxable from non-taxable bonds (e.g. pollution control bonds) to capture a better estimate of the cost of debt that is not skewed by tax-exempt bonds.

   Will S&P include short term debt?

   Yes, but David needs to confirm. S&P is not trying to get a bigger number, just a representative number of average cost of debt. Smaller rate drives NPV up, while interest expense decreases.

10. **What length PPAs will be considered for "evergreening" (i.e., assuming that a short-term PPA will be renewed for purposes of debt imputation)? Is there either a minimum or maximum contract length that must be met?**

    Evergreening is still under discussion and no answer at this time.

11. **How will evergreening actually work? Does evergreening just assume a one-time renewal of a PPA using the existing contract terms or could the evergreening extend to a longer period and/or change the terms of the PPA?**

    Evergreening is still under discussion and no answer at this time.

12. **Will S&P look at projected utility load/resource balances in determining whether or not to apply evergreening?**

    Evergreening is still under discussion and no answer at this time; however, S&P does recognize a utility's obligation to serve.

13. **What future self-build activity will S&P consider in determining whether or not to apply evergreening?**

    S&P would not evergreen contracts between the decision to build a plant and the on-line date.

14. **Does S&P offset PPAs with utility power sales agreements in imputing debt? If not, why?**

    Yes and No. S&P does not net one against the other. They do give credit to revenue from a sales agreement – which is in effect an offset.

    Does the recovery mechanism extend to the sales contract?

    It might cause a higher risk factor if not. The benefit of revenue tempers the obligation. The discussion was tabled and one party was interested in picking up the conversation off-line.

15. **What is the difference between how S&P has historically determined a proxy capacity portion of an energy-only contract and how S&P plans to make this determination in the future? Has this methodology differed by contract/utility in the past and will it differ by contract/utility in the future?**

    - Historically: S&P determined the capacity portion of an energy only contract as 50% energy, 50% capacity. In the future, S&P is discussing how to find a capacity "price" based on factors such as the cost of building a new marginal unit and the weighted average cost of capital. The price would then be based on the calculation of (kilowatt year basis*MW under contract).
    - Proposal: work towards capacity price based on the price to build capacity. Would not use existing price because it would penalize those who entered in at a high/low market).

- The price it would cost to add the next marginal unit multiplied by the WACC to derive a capacity recovery estimate and calculate the kw/yr times the number of MW under contract. Gives more favorable treatment than historically.
- Define the proxy amount by region and market.
- Wind would have different capacity factor. Possible ancillary transmission charges would be included in the wind component. Have not historically, but are considering them for the future.
- Price will be dynamic.

16. In the context of a typical wind PPA, is the new method for determining the capacity proxy likely to result in a larger or smaller amount of imputed debt?

David's anecdotal evidence leads him to believe it will lead to a smaller number of imputed debt.

17. Under the new guidelines, are there any energy-only contracts for which no capacity proxy will be assumed?

There is only one exception and that is when a utility is merely acting as a conduit.

18. What are S&P's views on using an equity adjustment to the capital structure used for ratemaking intended to offset imputed debt? Do they work?

Florida uses an equity adjustment to the capital structure and it does enhance the revenue stream.

19. What would S&P view more favorably, a mechanism that guarantees payment of PPAs (holding the company harmless of load changes) or an equity adjustment?

It depends on the situation. The pass-through allows for flexibility, but equity is important to the extent that it offsets imputed debt.

20. What is S&P's view on a utility earning a return on a PPA contract? How would that affect debt imputation? How would this be viewed differently than an equity adjustment to the capital structure (as in question #1)?

David's experience is that regulators are adverse to a return on commodities. Chances are remote to earn a return on contract; however, S&P would consider a return on contracts as an increase in revenue.

21. What attributes does a power cost adjustment mechanism (PCAM) need to have to earn the full PCAM adjustment in the risk factor? Which are most important?

- Allowance of recovery of the fixed costs,
- Whether there is pass-through mechanism,
- How often is there a true up, what is the trigger, and is it collected monthly, semi annually, annually, if a deferral, what are the conditions,
- Is there a legislative mandate guaranteeing recovery,
- These factors all bear different weight, with a legislative mandate for recovery bearing the most weight in favor of recovery.

22. Does a PCAM need to provide dollar-for-dollar cost recovery to lower the risk factor? Can a PCAM with deadband for cost recovery lower the risk factor? What level of recovery (90%, 75%, 50%, etc.) must a PCAM ultimately provide to lower the risk factor?

S&P looks to the triggers for cost recovery under a PCAM – whether it is a deferral, immediate cost recovery, degree of recovery, and over what time period the cost recovery occurs, etc.

23. What kind of mechanisms for prudence review are typically in PCAMs that have earned the full reduction of the risk factor?

Full reduction would require legislation with full recovery. Massachusetts/Virginia/Maryland have such mechanisms, this is possibly related to de-regulation.

24. Would a PCAM that covered PPAs only qualify as a PCAM that could reduce the risk factor? What about a PCAM that covered only the capacity portion of a PPA?

Possibly to 25%. It is applicable if capacity was recoverable. If no energy is in PCAM, it might impair risk profile (therefore need stronger financials to keep the same rating). Never seen before but if it existed then it would lower capacity risk factor but increase the risk to the utility as it is exposed to energy volatility.

25. Does S&P require a track record of performance under the PCAM before it will lower the risk factor?
S&P likely would not track the record of performance under a PCAM before it would lower the risk factor. If the risk factor were lowered due to a PCAM, it would only be on a case-by-case basis.

26. What states have legislated cost recovery of PPAs in a manner that has lowered the risk factor? Is Utah's pre-approval statute an example of a legislative cost-recovery mandate that qualifies for a risk factor reduction?

Massachusetts/Virginia/Maryland have legislated cost recovery of PPAs that has lowered the risk factor.

27. How do you give credit for risk-factor lowering circumstances in one state for a multi-state utility?

A multi-state utility would probably have its contracts prorated based on its presence in each state and would look to which states had PCAMs in the analysis. S&P would likely use a weighted average. David needs to confirm.

28. With respect to renewable PPAs, does S&P give the full legislative mandate risk factor reduction to cost recovery provisions in RPS statutes? Does it depend on the specific language of the mandate? What attributes are most important?

There is no distinguishing between renewable PPAs and other PPAs. Unless renewables are securitization, they are not different. They are lumped together for cost recovery unless legislation accounted for a different cost recovery for renewables.

29. Is it possible for a vertically integrated utility to reduce its risk factor to zero?

There are two choices 1) legislation, or 2) buy all energy on spot market. There would be no imputed debt, but the risk will increase dramatically.