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October 16, 2008

Arizona Corporation Commission
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AZ CORP COMMISSION
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Jeff Hatch-Miller, Commissioner
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Gary Pierce, Commissioner
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: RESPONSE TO COMMISSIONER REQUESTS IN THE MATTER OF THE APPLICATION OF A CONCENTRATING SOLAR POWER CONTRACT DOCKET NO. E-01345A-08-0106

Dear Commissioners:

Arizona Public Service ("APS" or "Company") is providing the following response to various Commissioners' requests for supplemental information that arose at the September 24, 2008 Open Meeting during discussions related to the Company's Solana Purchased Power Agreement ("PPA") docket. If any of the Commissioners would like to further discuss the information provided below, APS would be happy to meet with you on an individual basis.

Impact of the Lieberman-Warner Bill on APS and Above Market Costs for Solana

Based on a request for additional information regarding the economic impact of the proposed Lieberman-Warner legislation ("L-W Bill") on the above market cost of Solana energy, APS provides the following information. The L-W Bill would establish a greenhouse gas hybrid cap and trade program with emissions targets that decrease allowable emissions through time. Because the composition of APS's power supply portfolio is largely fixed in the near-term, the potential cost impacts to APS are primarily dependent on carbon dioxide ("CO_2") reduction targets and their associated timeframes, allowance allocation schemes, and emission allowance prices. In addition to other factors, emission allowance prices will be dependent upon natural gas prices that affect the cost of fuel switching, the ability to utilize carbon offsets for compliance purposes, and the supply/demand balance, which in turn is impacted by the level of the reduction targets.

The potential cost impact of the L-W Bill varies, based on APS's estimated allowance deficiency and the assumed CO_2 price per metric ton. A number of industry participants have developed estimated price ranges for CO_2 prices. In its analysis, APS used low and high price range projections from the Environmental Protection Agency and Science Applications International Corporation. Assuming an allowance deficiency of 11.8 million metric tons in 2015,[1] the economic impact to APS based on a CO_2 price range of $29 per metric ton would result in a projected cost impact in 2015 of $342 million; with a price of $64 per metric ton, the projected cost rises to $755 million. The resulting projected rate impact for 2015 would be in the range of an 11% to 25% increase in APS's annual revenue requirement.

When CO_2 costs are included in cost comparisons, it is possible that Solana could be either approximately equivalent to or below the cost of conventional resources. With an assumed emission allowance price of $25 per metric ton in 2012 (escalating at 3% per year), the estimated above market cost would decrease from 19% to 5%. If the emission allowance price was $35 per ton, the cost for Solana and other conventional resources would reach parity at 100% of avoided cost.

Transmission Analysis 2007 Renewable Request For Proposal ("RFP")

In response to questions regarding the evaluation of transmission system impacts and upgrades necessary for projects proposed in response to the 2007 Renewable RFP, APS provides the following information. APS retained Navigant Consulting to serve as its independent auditor for the 2007 Renewable RFP process. Navigant issued a report that included a description of the Transmission Analysis.[2] The transmission analysis APS conducted during the 2007 Renewable RFP was used to determine the risk level associated with the potential delivery of the project's energy to the APS load and what additional costs, if any, should be added to the bid price for transmission delivery to the APS load.

The additional transmission and/or wheeling costs were determined based on the need to bring the potential resource to APS load, given the existing and planned APS transmission system, as well as the location of delivery on the APS system. These costs, if any, were then factored into the economic analysis. The analysis made the following assumptions:

- All transmission available for APS future resources was assumed to be available for the RFP bids, just as it would be for a conventional resource.

[1] Based upon APS's interpretation of the provisions of the L-W Bill and APS's forecast of future CO_2 emissions.

[2] *See* Independent Auditor Report for the 2007 Renewable RFP Process, Navigant Consulting (Mar. 4, 2008) at Section 3.2.1. This report was attached to the Staff Report that was filed on September 10, 2008 in this docket.

- If new transmission was needed to allow delivery of the project output to APS load, only the proportionate share of the new transmission was included as a cost adder for the project, rather than the full incremental cost of the new transmission.

- If transmission was not available on APS's system and if transmission wheeling from another provider's system might allow the bid to be delivered to APS load, only the cost of transmission wheeling was added to the cost of the project.

- If the potential resource was delivered along the constrained APS eastern transmission path,[3] an "energy only" approach was analyzed in addition to evaluating the "new transmission" costs, to determine the most economical option. In the energy only analysis approach, no incremental transmission cost was added to the project, no capacity value was assigned to the project, and virtually all of the energy was assumed to be delivered.

It is significant to note that as described above, during the evaluation of responses to the 2007 Renewable RFP, all wind projects were evaluated in the most favorable manner given the configuration and utilization of the existing transmission system.

Clarification on Imputed Debt for Solana

Related to the issue of imputed debt for the Solana PPA, clarification was requested for: (1) the impact of the Solana PPA on the Company's financial metrics and when that impact will occur; and (2) the extent to which the Company's representations on this issue at the Open Meeting on the Solana matter differ from those made at the Open Meeting regarding Pinnacle West's equity infusion application.[4]

In regard to the first inquiry, when determining a company's capital structure, level of debt and related interest obligations for the purpose of assessing its creditworthiness, credit rating agencies generally impute a portion of any outstanding long-term PPA obligations as added debt. Of the rating agencies, Standard & Poor's ("S&P") uses the most transparent methodology for calculating imputed debt, and APS thus uses S&P's methodology to analyze the imputed debt impact of the Company's PPAs. Because of the long-term financial obligations that APS will incur under the Solana PPA, S&P will impute as additional debt on the Company's balance sheet roughly $80 million in 2011 (a number that recently increased from $55 million due to a change in S&P's methodology). Among other impacts, this imputation will increase the debt denominator of the Company's FFO/Debt ratio, thereby slightly lowering that metric for each year of the contract's life.

As explained in an article published by S&P (attached to this letter as "Attachment A") and the spreadsheet demonstrating the specific imputed debt calculation that applies to the Solana

[3] The eastern transmission path is defined here as the path including the Four Corners to Cholla 345kV lines, the Cholla to Pinnacle Peak 345kV lines, the Cholla to Saguaro 500kV line, and the Saguaro to Kyrene 230kV line(s).
[4] July 28, 2008 Open Meeting; Docket No. E-01345A-08-0228.

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contract (attached as "Attachment B"), S&P calculates this amount as follows. First, because S&P is interested only in the "fixed" payments associated with a PPA (and not in the variable costs related to items such as fuel), it identifies the stream of "fixed" capacity payments that will be made by the utility under the PPA. If no explicit capacity payment obligation exists in the contract (as is the case with Solana, which has a "full output" energy agreement with APS), S&P will make reasonable assumptions about the amount of costs that can be considered more or less "fixed" by the contract. In the case of Solana and other "energy-only" contracts, S&P's current methodology results in assumed capacity payments that are approximately 10% to 25% of the total payments that APS will make under the PPA.[5] S&P then calculates the net present value of those "fixed" payments using, among other factors, a discount rate that is generally equal to the Company's average cost of debt.[6]

Next, S&P multiplies that present value payment amount by a utility-specific "Risk Factor," determined by the agency, which is intended to reflect the regulatory risk assumed by the utility for recovering the costs paid under the PPA.[7] It then increases the debt portion of the Company's balance sheet by that final amount (in other words, it imputes this risk-adjusted, net present value capacity or other "fixed" payment amount as debt).[8] The debt imputation will not occur, however, until the year that energy deliveries begin under the contract, even if the contract is executed before that time.[9] As a result, in this case, the Solana PPA will not have **any** impact on the Company's financial metrics until at least 2011, the first year in which Solana is expected to be operational, and at which point APS is required to take energy under the contract.

With respect to the second inquiry, during the Open Meeting on the equity infusion application, the Company was asked about the impact of Solana on the Company's FFO/Debt ratio and whether the $4 billion notional value of the contract would be imputed as debt by the rating agencies. In response, an APS representative correctly indicated that, while the notional value of the Solana contract was $4 billion, S&P will look only at the capacity portion of those payments, not the entirety of the payments made over the life of the contract, and that a 50% Risk Factor will be applied to that amount.[10] The representative also correctly noted the imputation would not occur until "the point when the plant goes operational, not at the point that the contract is signed. . . ."[11]

The APS spokesperson then attempted to perform a rough calculation illustrative of this discussion, and, in doing so, noted that the imputed debt amount could be $1 billion. The spokesperson made the calculation in attempt to show generally the formula that S&P applies, and did not have any dollar figures or analysis specific to the Solana agreement available to her

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[5] *See* Attachment B at lines 1-5 for detail regarding the specific annual capacity payments attributed to the Solana contract under S&P's analysis.

[6] *See* Attachment A at 1; Attachment B at line 8.

[7] *See* Attachment A at 2; Attachment B at line 9.

[8] As shown on Attachment B at line 10, that amount for Solana is approximately $80 million. If the 35% Risk Factor historically attributed to APS is applied, that number is reduced to $55 million, as noted at the Open Meeting regarding the Solana docket.

[9] *See* Attachment A at 1.

[10] *See* Equity Infusion Open Meeting Transcript at 21:24 – 23:23.

[11] *Id.* at 24:8-13.

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at the time. As a result, she substantially overestimated the amount of the annual capacity payments S&P would attribute to APS under the contract, and neglected to include the impact of S&P's net present value calculation on that amount. During the same discussion, another APS representative then clarified that the S&P imputed debt calculation focuses on the net present value of the assumed capacity payments, and stated that, as a result, "the imputed debt figure that we're talking about is going to be less" than the $1 billion referenced.

As noted above and as outlined in Attachment B, when the net present value of the assumed capacity payments is calculated, APS anticipates approximately $80 million of debt imputation at the time the Solana agreement commences in 2011. APS apologizes for any confusion it created by not having the specific figures necessary for the imputation calculation available during the equity infusion Open Meeting.

If you have any additional questions, or would like to meet with Company representatives to discuss these issues in greater depth, please call me at 602-250-5508.

Sincerely,

Deborah R. Scott
Senior Regulatory Attorney

Attachment

cc: Docket Control
Brian McNeil
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Attachment A

STANDARD & POOR'S **RatingsDirect**

RESEARCH

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

Publication date: 07-May-2007
Primary Credit Analyst: David Bodek, New York (1) 212-438-7969; david_bodek@standardandpoors.com
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For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied deprecation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity. We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

Additional Contacts:

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Attachment B

ATTACHMENT B

Solana PPA Imputed Debt

S&P Method

1	Plant Capacity - MW	283
2	Capacity Factor	36%
3	Avg. Capacity - MW	102
4	2011 Proxy Capacity Cost - $/KW Yr	120
5	Capacity Payment - $MM	12
6	Length of PPA - years	30
7	S&P Discount Rate	6.3%
8	NPV of Capacity Payments - $MM	$163
9	Risk Factor	50%
10	Debt Equivalent Yr 1 - $MM	82

Note: Numbers vary slightly from calculation filed by APS with the ACC in the Solana PPA docket due to rounding and simplification of the schedule.