BEFORE THE ARIZONA CORPORATION COMMISSION



Bob Stump, Chairman
Gary Pierce, Commissioner
Brenda Burns, Commissioner
Bob Burns, Commissioner
Susan Bitter Smith, Commissioner

IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT

Docket No. E-00000V-13-0070

ORIGINAL

**COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION ON ARIZONA PUBLIC SERVICE COMPANY AND TUCSON ELECTRIC POWER'S 2014 INTEGRATED RESOURCE PLANS**

## I. INTRODUCTION

The Solar Energy Industries Association (SEIA)[1] appreciates the opportunity to provide these comments on the 2014 Integrated Resource Plans (IRPs) submitted by Arizona Public Service Company (APS) and Tucson Electric Power (TEP). SEIA has analyzed the information in these plans, with a particular focus on the resource portfolios that include higher amounts of renewable energy. Our analysis concludes that procuring additional renewable resources beyond what the utilities have proposed in their base portfolios[2] is beneficial to ratepayers. Moreover, we identify certain shortcomings in each plan's assumptions that further support this conclusion. We also provide comments on the purported need for flexible resources to facilitate renewable energy integration. And finally, we offer recommendations on how the Commission should conduct its own analysis of the plans and suggest changes to be made prior to Commission acknowledgement.

## II. IRP BASE PORTFOLIOS

[1] The comments contained in this filing represent the position of SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.
[2] For APS, we used the Coal Reduction portfolio as the "base portfolio" in accordance with the changes announced at the September 11, 2014 workshop. For TEP we used the Reference Case as the "base portfolio."

***APS and TEP's base resource portfolios anticipate meeting customers' future energy needs primarily with natural gas and a minimal amount of renewables.***

Both APS and TEP are planning to rely predominately on natural gas to fulfill future energy and capacity needs. Over the next 14 years, TEP plans to meet approximately two thirds of its incremental energy needs (GWh above 2014 levels) from natural gas and purchased power.[3] Meanwhile, APS will meet approximately half of its incremental energy needs from natural gas over the next 15 years.[4] While some incremental renewable resource additions are included in each company's base plan, the amount is relatively small in comparison to the additional natural gas (see Figures 1 and 2). Natural gas (including purchased power) accounts for four times as much of the incremental energy needs as renewables in TEP's case, and three times as much in APS' case. In TEP's case, the IRP does not even anticipate adding sufficient RE resources needed to meet the company's Renewable Energy Standard (RES) requirements. For each year after 2017, the amount of renewable resources TEP anticipates in its IRP is less than the percentage of retail sales required by the RES. [5] This is true despite the fact that in its 2015 REST plan, TEP suggested that the company will continue to "invest in renewable technologies in the future as the Company transitions to a more sustainable resource portfolio, but will recover those costs through traditional methods." [6] Yet, TEP's IRP indicates that no incremental RE additions (other than DE) are planned from 2015 until 2022.[7] This oversight needs to be corrected in the final version of the IRP acknowledged by the Commission. For APS, the Coal Reduction portfolio anticipates procuring renewables sufficient to meet the REST requirements and 2009 Settlement Agreement, but still remains close to the minimum amount needed.

[3] Computed from data on Chart 6 of TEP's 2014 IRP.
[4] Computed from data on APS' 2014 IRP, F.1(a)(3): Coal Reduction Portfolio – Energy Mix, p 307.
[5] Computed from data on Chart 6 and Table 7 of TEP's 2014 IRP
[6] TEP 2015 REST Implementation Plan, p 5, filed 7/1/2014 in Docket No. E-01933A-14-0248
[7] See TEP 2014 IRP, Table 3.

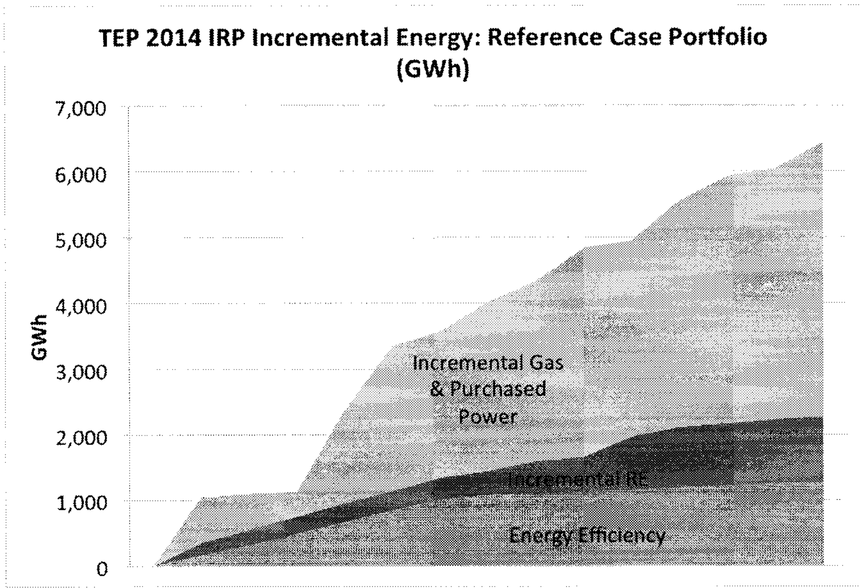


**Figure 1. Illustration of resources used to meet incremental energy needs (GWh above 2014 values) in TEP's 2014 IRP Reference Case Portfolio. Computed from data on Chart 6 of the IRP.**

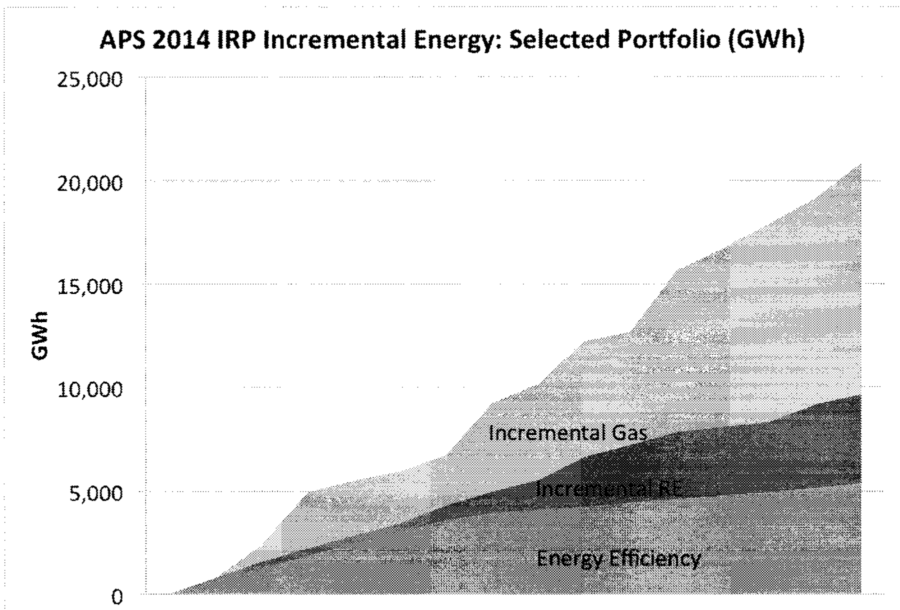


**Figure 2, Illustration of resources used to meet incremental energy needs (GWh above 2014 values) in APS's 2014 IRP Coal Reduction. Computed from data on APS' 2014 IRP, F.1(a)(3): Coal Reduction – Energy Mix, p 307.**

***Over the long term, ratepayer costs are dominated by fuel-related expenses associated with rising natural gas prices.***

Despite the recent availability of shale gas resources, the market still anticipates natural gas prices to rise substantially in the future. For example, APS projects that natural gas prices will rise from approximately $4.04/MMBTU in 2014 to $7.51/MMBTU in 2029.[8] TEP similarly projects prices to rise from $4.47/MMBTU to $7.36/MMBTU over the same time period. This increase in fuel costs is a major driver of increases in future revenue requirements. For example, in APS' case, the fuel-related components of the revenue requirement increase from $533 million in 2014 to $1,895 million in 2029 (a 255% increase).[9] Moreover, fuel-related costs grow to become a larger share of overall system costs than any other component, increasing from 24% to 39% of overall system costs by 2029 (see Figure 3). Similar trends were observed in TEP's IRP data obtained via a confidential data request. This shift puts customers at greater financial risk since fuel costs are largely passed through to customers and not borne by the utility. Although utilities engage in some short-term hedging programs to reduce the effects of fuel price volatility, this does not protect customers from long-term fuel price trends. Unlike renewables, gas plants also pose the additional risk of becoming stranded assets if fuel prices were to increase substantially, or additional environmental regulations restrict their use. In this way, investing in new natural gas plants in the near-term could lock customers in to rising costs over the long-term as fuel prices increase or new risk factors come into play.

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[8] See TEP 2014 IRP, p 305; APS 2014 IRP p 246, Attachment D.1(a) (4) - Average Fuel Cost.

[9] Computed from data in APS 2014 IRP, p 316, Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements, Coal Reduction Portfolio. For this analysis, fuel-related components included commodity fuel purchases, emissions costs, and gas transportation costs.

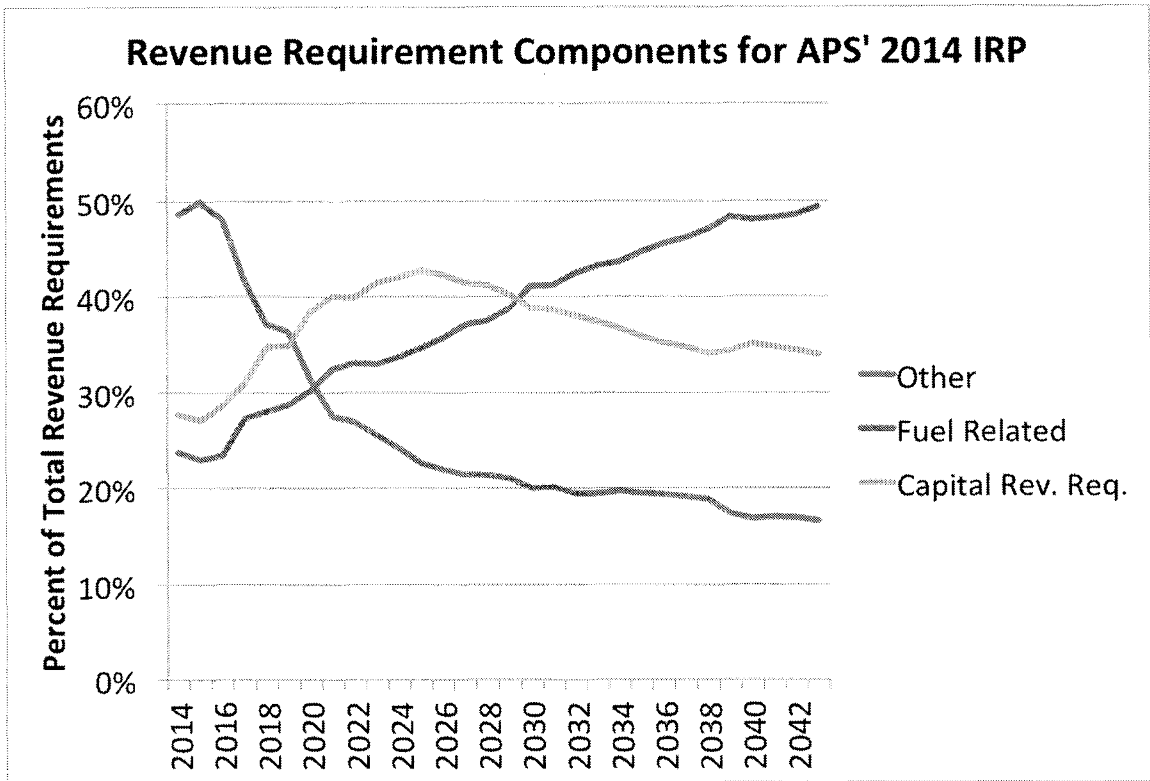


Figure 3. Percent of overall system costs derived from Fuel-related, Capital, and Other cost categories for APS. Over time, fuel-related costs (in red) increase substantially as a percent of overall system costs. Data compiled from APS 2014 IRP, p 316, Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements, Coal Reduction Portfolio.

## III. COMPARISON OF HIGH RE PORTFOLIOS TO BASE PORTFOLIOS

***Resource portfolios with more renewable resources substantially mitigate the fuel price risk to customers.***

In their 2014 plans, both APS and TEP studied resource portfolios with substantially more renewable energy than the base portfolios. In both cases, these "High RE Portfolios" anticipated 25% renewable energy by 2025, rather than the 15% that is currently required. Since the High RE Portfolios have lower fuel consumption relative to the base portfolios, they have correspondingly lower fuel costs. Over time, this provides a steadily increasing dividend to ratepayers in the form of avoided fuel costs. For example, relative to APS' Coal Reduction Portfolio, its Enhanced Renewables Portfolio is anticipated to reduce annual fuel-related costs by $69 million in 2020, increasing to $272 million in 2029 (see Figure 4). Similar trends were observed in TEP's IRP data obtained via a confidential data request. Once again, this benefit is amplified by the fact that fuel is generally a pass-through cost, posing significant price risk to ratepayers while virtually none to the utility.

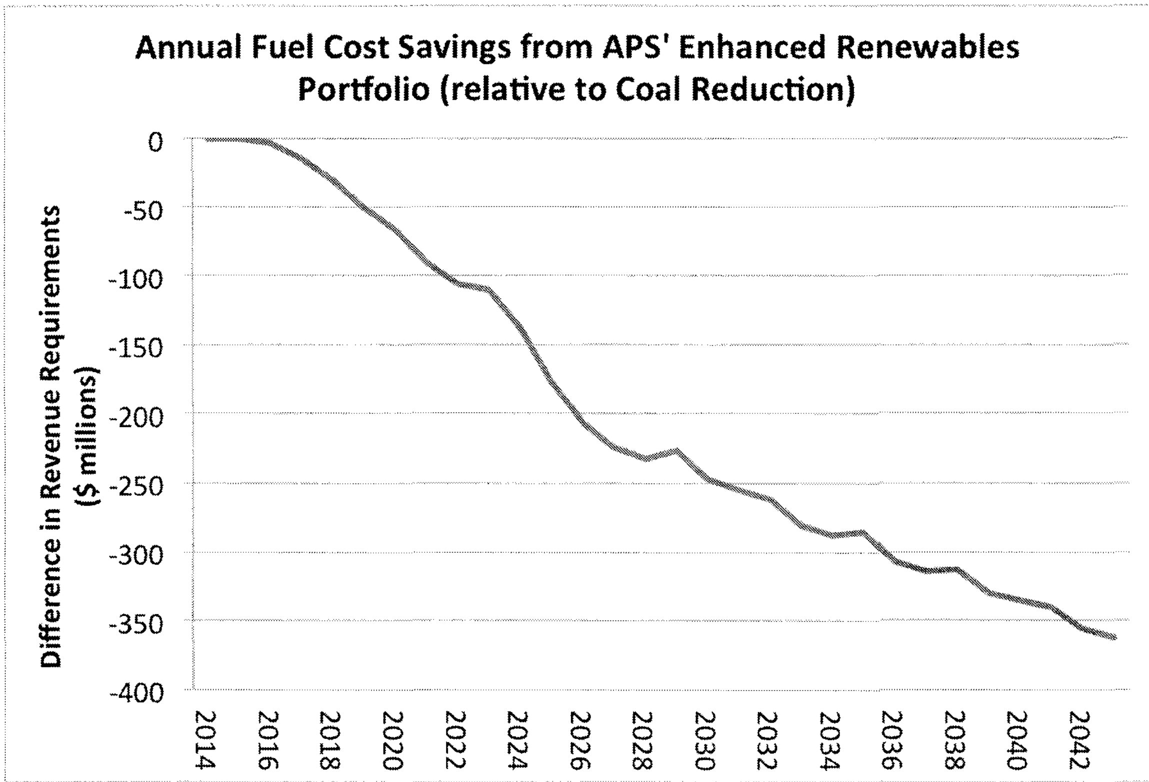


**Figure 4. Difference in the fuel-related revenue requirements for APS' Enhanced Renewables Portfolio versus the Coal Reduction Portfolio. The Enhanced RE Portfolio exhibits an increasingly lower amount of overall fuel costs. Data compiled from APS 2014 IRP, Attachment F.1(b) - Analysis of Six Portfolios (Current Path Scenario): Key Metrics: Revenue Requirements, Coal Reduction Portfolio (p 316) & Enhanced Renewable Portfolio (p 315)**

***Under base case assumptions, the incremental cost of the High RE Portfolios is relatively small.***

Under APS's Coal Reduction Portfolio and Current Path assumptions, the average system cost ($/MWh) increases from $73.6/MWh in 2014 to $117/MWh in 2029 – a 59% increase.[10] Meanwhile, under APS's Enhanced Renewables portfolio, the average system cost increases to $118.9/MWh in 2029, which is only 2% higher than the Coal Reduction portfolio (see Figure 5).[11] Similar trends were observed in TEP's IRP data obtained via a confidential data request.

[10] See APS 2014 IRP p 314.
[11] See APS 2014 IRP p 315. During the interim years, this cost differential fluctuates, but does not deviate beyond 0-4% and is 2.5% on average.

Thus, the incremental cost of additional renewables appears to be relatively small compared to the overall increase in system costs over time. In SEIA's opinion, the cost of the High RE Portfolios is essentially "in the noise." Performing a Net Present Value (NPV) calculation draws a similar conclusion. According to APS' analysis increasing renewable energy to 25% of retail sales (by 2025) would increase the NPV Revenue Requirement (2014-29) by 2.5% above the Coal Reduction Portfolio. For TEP, the same increase in renewables yields a 3.8% increase in NPV Revenue Requirement above the Reference Case.

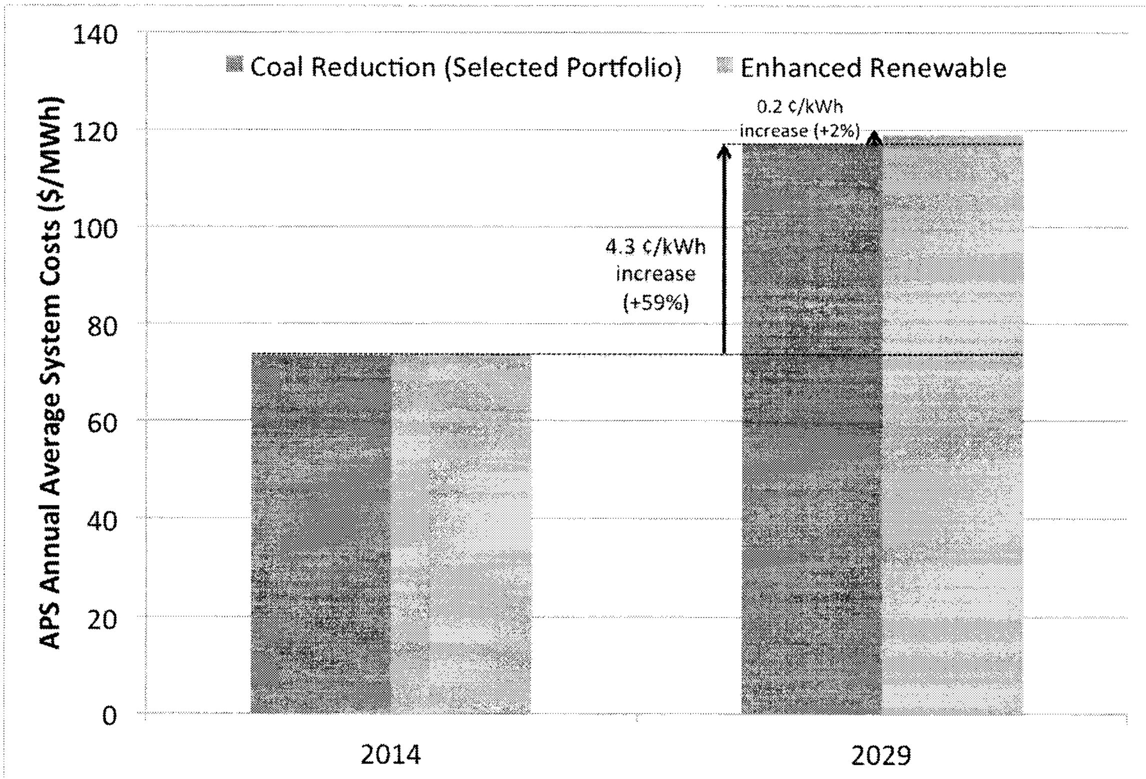


**Figure 5. Comparison of the increase in APS' average system costs for the Coal Reduction Portfolio and the APS Enhanced Renewables portfolio. Under base case assumptions, the Enhanced Renewables portfolio would increase system costs by 2% above the 59% increase expected by the Coal Reduction Portfolio in 2029. Data compiled from APS 2014 IRP p 315-316.**

Thus, according to the IRPs' base case assumptions, the High RE Portfolios do appear to increase overall costs to ratepayers, but the increases are relatively small. SEIA believes that these incremental costs are justified after taking into account the potential fuel price risks to ratepayers and potential for long-term savings. To put it another way, the small incremental cost of the High RE Portfolios can be thought of as an insurance policy, or hedge, for customers against future price increases. Furthermore, as discussed in the next section, we believe that certain base case assumptions used in the plans are incorrect. If these assumptions were corrected, the end result would give even more support for the High RE Portfolios.

***Scenario analysis suggests that the High RE Portfolios are likely to yield costs savings to customers (relative to the base portfolios).***

In APS' IRP, the company studied several scenarios with modified assumptions including an "Increased Environment Policy" scenario. The inputs and assumptions for this scenario were adjusted from the base case as follows:

- High carbon prices
- Increased shale gas regulation
- Additional coal plant environmental control requirements
- Nationwide coal retirements
- Increased demand for renewable energy, leading to increased capital costs
- Continuation of the ITC/PTC

Under this scenario, the Enhanced Renewables Portfolio was the *least costly* option on a NPV basis. Meanwhile, it is SEIA's opinion that virtually all of the factors listed above that comprise this scenario are either already in effect or will soon be reality, with the possible exceptions the last two inputs listed. Regarding the first of these exceptions, "Increased demand for renewable energy, leading to increased capital costs" SEIA notes that the opposite has actually been true in recent history. That is, as demand for renewable energy has increased, the capital costs for renewable energy have actually declined as these technologies have advanced down the learning curve (see Figure 6). SEIA believes these cost declines will continue over time, and thus the High RE Portfolios are likely to be even more favorable under this scenario. Regarding the second exception, "Continuation of the ITC/PTC", SEIA successfully lobbied for the first ITC extension in 2008 and we believe there is a strong possibility that the ITC will further extended beyond 2015. Given the likelihood of all the factors in this scenario, it appears increasingly likely that the Enhanced Renewable Portfolio will be the least expensive, and least risky option for ratepayers.

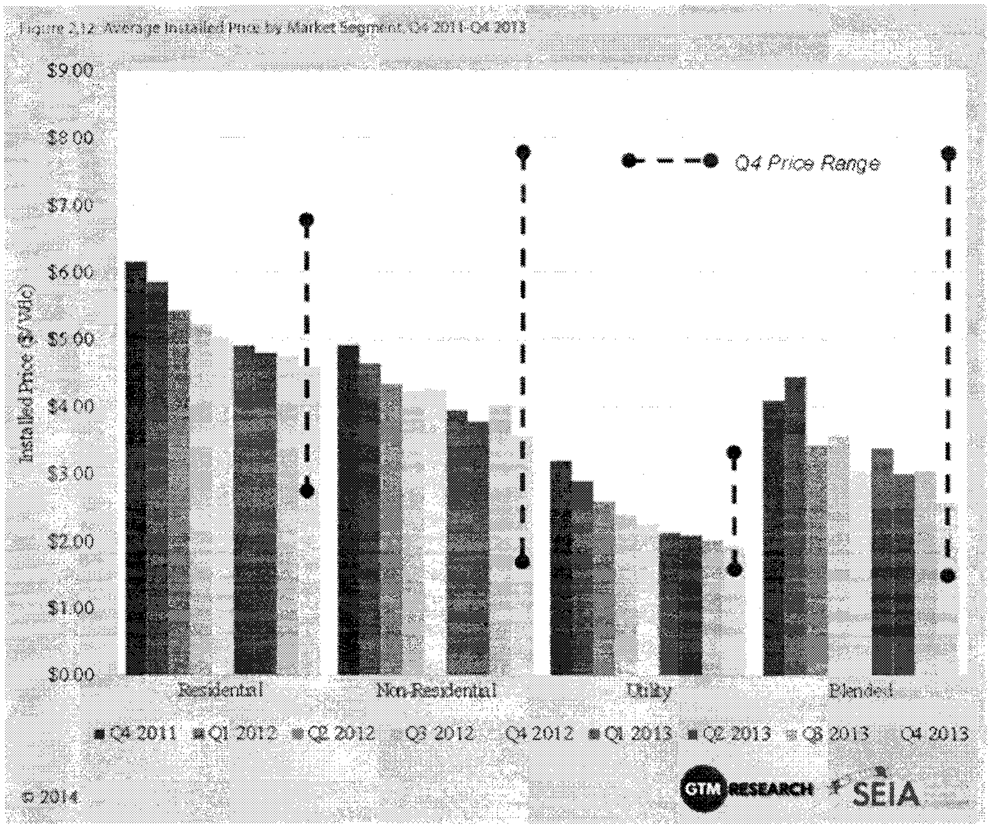


**Figure 6. Illustration of the recent declines in solar PV prices (Source: SEIA 2014).**

***Updating the IRP cost assumptions would further support the High RE Portfolios.***

In its 2012 IRP, APS presented a resource cost comparison showing solar to be nearly cost-competitive with natural gas (on an LCOE basis), and significantly cheaper than nuclear and coal. While APS did not include a similar cost comparison in their 2014 plan, SEIA compared the updated costs via an informal data request. The changes from 2012 to 2014 are puzzling and seem to defy industry trends. For example, the LCOE for nuclear dropped from $160/MWh to $127/MWh, while gas dropped from $105/MWh to $91/MWh despite increases in gas prices over this interval. Meanwhile Solar PV (SAT) increased from approximately $85/MWh in 2012 to $126-140/MWh in 2014 despite continued reductions in solar PV costs over the same timeframe. TEP's 2014 plan also reports solar LCOE numbers that are above the 2012 costs. For instance, Solar PV (SAT) increases from $144/MWh to $166/MWh.[12] In contrast, solar PPA contracts have recently been signed in nearby jurisdictions ranging from $45/MWh to

[12] Corrected form the earlier value of $184/MWh.

$70/MWh.[13] While we understand that some cost increase may be intended to reflect the recent flattening of PV module prices, this should be seen as a temporary effect related to cyclical supply chain issues and is not indicative of long-term solar PV price trends driven by technological improvements and investments in new manufacturing facilities. Additionally, we also recognize that the possible expiration of the 30% Investment Tax Credit on January 1, 2016 (reverting to 10%) may have an effect on solar costs, however we do not think this explains the large discrepancy between APS' and TEP's IRP assumptions and recent solar PPA prices. Finally, we disagree with the inclusion of "backup capacity" as a component of energy resource costs since the addition of solar does not necessarily require the simultaneous addition of backup capacity. SEIA believes the cost assumptions for solar in the IRPs should be adjusted according to these factors listed above.

Additionally, it's worth noting that the High RE Portfolios appear to have very similar gas plant build-outs to the base portfolios, despite different levels of plant utilization. For instance, the capacity factor of gas resources in APS' Enhanced Renewables Portfolio is 16% in 2028 versus 25% in the Coal Reduction Portfolio.[14] Thus, there may be additional opportunities for Cap-Ex cost reduction in the High RE portfolios – particularly through reduced construction of Combined Cycle plants which function primarily as energy resources and are not as capable of offering flexible capacity as simple Combustion Turbines.

## III. COMMENTS ON FLEXIBILE RESOURCES FOR RENEWABLE INTEGRATION

***The IRPs propose additional natural gas power plants to provide flexibility needed for renewable energy integration.***

Both APS and TEP identify new natural gas additions – particularly fast-start CT units – that are purportedly necessary to provide operational flexibility as the penetration of solar PV resources increases. For example, APS states the following: "Included in each portfolio is the assumption that APS's aging Ocotillo Steam units are retired and the site modernized by including five new LMS100 combustion turbines. This reflects the importance of the Ocotillo site in terms of reliability in the Phoenix load pocket, as well as meeting the need for increased flexibility that will be required as more variable resources come on to APS system and the

[13] http://www.energyprospects.com/archives/288-print.html
[14] Computed from data in APS' 2014 IRP, Attachments F.1(a)(3-4): pp 304-7.

Southwest power market in general." Similarly, TEP states: "Quick-start combustion turbines with low unit minimums and fast ramping resources such as pumped-storage plants are good complements to integrating intermittent renewable resources into existing power systems."[15]

SEIA is encouraged that both utilities are planning for higher penetrations of renewable resources, and we share in the desire to make sure that the bulk electric system is well equipped to accommodate this transition. However, we have some concerns with the way the need for new natural gas resources is characterized. In particular, we are wary that new natural gas additions could lead to significant ratepayer costs that may in turn be falsely attributed to solar (particularly DG). SEIA notes that flexible resources are needed for a variety of reasons and we think it is a mistake to attribute these needs solely to the increase in solar resources. Furthermore, we are concerned that utility-owned natural gas capacity being planned on the premise of "flexibility needs" could crowd out competition from other potential resources (e.g. PPAs). To avoid these concerns, the plans should ideally contain substantial evidence about the quantity and timing of the flexible resource need.

***There is little evidence in the IRPs that new natural gas units are necessary to meet flexibility needs in the short term.***

The utilities have described the need for flexible resources in broad terms, but have not demonstrated this need quantitatively, through robust reliability analysis. While the need for new flexible resources may be warranted in some instances and should be encouraged in those instances, it is difficult to discern the validity of these claims from the plans presented. It is even more difficult to discern whether new natural gas capacity is the only option available for meeting these flexibility needs. Indeed, many options besides new gas are capable of meeting flexibility needs, potentially at lower cost (see Figure 7). Yet, the plans do not adequately consider this wide variety of options. For example, Concentrating Solar Power (CSP) with thermal energy storage is a flexible renewable that can provide dispatchable energy whenever it is needed, day or night, and hedge against the future price of natural gas. As such, the new gas resources built to meet flexibility needs in the High RE scenarios may artificially inflate the cost

[15] TEP 2014 IRP, p 259.

of those scenarios.

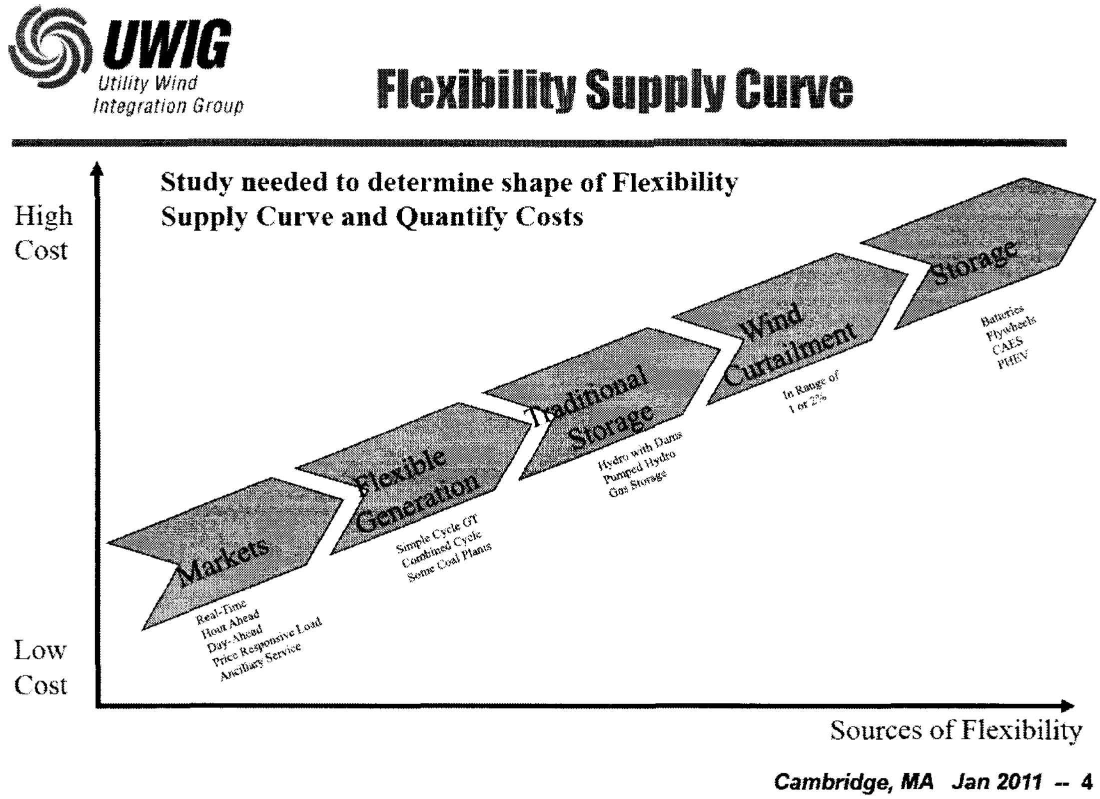


**Figure 7. Conceptual illustration of a Flexibility Supply Curve illustrating the wide range of options available to utilities for renewable energy integration (Source: Charles Smith, Utility Wind Integration Group, 2011.)**

## IV. SEIA's CONCLUSIONS AND RECOMMENDATIONS

The base portfolios suggested by the utilities in their resource plans may put ratepayers at unnecessary risk of rising fuel prices since they rely so heavily on gas investments. Diverting some of this investment to renewable energy reduces that risk, but that benefit is not fully captured in the utilities' IRP analysis. Not only is the risk to ratepayers substantially reduced, but cost savings are likely to occur given recent trends in environmental regulations. Thus the High RE Portfolios appear to be the most prudent from a ratepayer perspective.

***Recommendation 1: Use High RE Portfolios as the Base Portfolios.***

Because of the significant long-term benefits RE provides in terms of lowering customer exposure to rising fuel costs, and the potential costs savings (or very small possibility for cost increase), the Commission should require utilities to use the High RE portfolios as their base portfolios. In TEP's case this would resolve the fact that their Reference Case does not even meet the requirements of the REST. Acknowledgement of each IRP should be contingent upon this change.

***Recommendation 2: Focus Commission analysis on future risk and cost to ratepayers.***

SEIA suggests that the Commission's report on the utilities' IRP filings include an analysis of how much these portfolios shift risk between ratepayers and shareholders. In performing this analysis, the Commission should be guided by the following questions:

- How is risk redistributed between ratepayers and shareholders over time in light of rising fuel costs?
- How should future fuel costs be discounted to reflect the ratepayer's perspective?
- How should the commission view potential mitigation strategies, including:
    - Option 1: Utility bears greater share of fuel price risk.
    - Option 2: Utilities divert more investment to resources that don't require fuel.

***Recommendation 3: Update the assumptions in the APS and TEP IRPs to more accurately reflect current and future market costs for solar as well as future environmental policies.***

As explained above, we believe the plans have distorted cost assumptions that need to be corrected. These corrections include solar cost assumptions both in the near term and in the future as costs decline due to technology improvements. Examples of recent PPA prices and assumptions for the future cost trajectory of solar should also be made explicit in each plan. Additionally, the assumptions about future environmental policies and regulations should be updated to more accurately reflect recent trends.

***Recommendation 4: Establish a method for quantifying the need for flexible resources and require consideration of all options for meeting those needs***

Each IRP should be revised to include a method for quantifying flexible resource needs that is somewhat analogous to peak load. For instance, a utility might identify a specific operating constraint (e.g. 3-hour continuous ramping capability) that might necessitate resource additions and report on how close the utility is to violating the constraint. Other states grappling with high penetrations of renewable resources are developing similar methodologies and could serve as an example. This more rigorous approach would better serve ratepayers by offering a deeper consideration of the need, rather than rubber-stamping a plan that primarily benefits utility shareholders. Furthermore, as mentioned above, utilities have several options for meeting flexibility needs besides natural gas and should be required to report on the cost and availability of each of these, including concentrated solar power (CSP) with thermal energy storage. Just as utilities develop an energy supply curve by reporting on the cost of energy and capacity for other resources, they could construct a similar "flexibility supply curve."

Respectfully submitted this 29th day of September, 2014.

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