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AZ CORP COMMISSION
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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
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AUG 29 2013

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COMMISSIONERS

BOB STUMP, Chairman
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SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF NET METERING COST SHIFT SOLUTION	DOCKET NO. E-01345A-13-0248 **APS NOTICE OF FILING DATA REQUESTS AND RESPONSES**

In response to the letter from Commissioner Susan Bitter Smith requesting parties to file all data requests and responses in this docket, APS hereby files its responses to date for data requests the Company has received. Additional responses will be docketed as they become available. APS has not issued any data requests to other parties.

RESPECTFULLY SUBMITTED this 29th day of August, 2013.

By: ______________________________
Thomas A. Loquvam
Deborah R. Scott
Attorneys for Arizona Public Service Company

ORIGINAL and thirteen (13) copies of the foregoing filed this 29th day of August 2013, with:

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing delivered
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Staff 1.1: Has DG and or EE pushed out the date of your next generation unit? Please explain.

Response: To date, DG has not deferred the date of the next generating unit. If, over the next several years, (i) customers install DG in the manner predicted; and (ii) load growth occurs as APS predicts, DG deployment will defer APS' next projected conventional generation unit addition in year 2017. This deferral is already included in the SAIC capacity benefit calculation for years 2020 and 2025. EE was included as part of the load forecast that was used in the SAIC study, but is not a relevant factor when calculating the cost shift that is occurring due to DG installations.

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Staff 1.2: If DG does defer and avoid generation, how should DG customers be reimbursed?

Response: APS believes that a rooftop solar customer should be compensated for the services that they no longer require from APS, or that they reduce the usage of, such as generation, fuel and variable O&M. Furthermore, this compensation should be based on today's prices for those services, not long term projections of costs or prices. For example, if a rooftop solar customer can reduce their usage of generation capacity and fuel, they should receive bill savings or credits for those reduced services based on the current unbundled rates for those services. If the price of fuel and generation capacity grows over time, so too will the bill savings or credits.

APS does not believe that it is appropriate or fair to base the bill savings for rooftop solar on levelized long term projections of utility cost savings because our rates are based on current Test Year costs necessary to serve customers.

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Staff 1.3: Please provide a map (in ARCGIS shape file format) that depicts all current customer sited distributed generation sites within APS's service territory together with a postal zip code boundary overlay. Differentiate between DG technology type (i.e. solar pv, wind, geothermal, biogas, etc.) and whether the site is a residential or commercial installation.

Response: The Company's response to Staff 1.3 contains confidential customer data and is provided to Staff pursuant to an executed Protective Agreement.

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Staff 1.4: Please provide your estimate of the ancillary benefits of renewable DG noted in the Crossborder study, including price mitigation, grid security, and economic development. Provide a discussion of how these benefits are quantified and your assessment of the value of these benefits.

Response: APS does not believe that the ancillary benefits of rooftop solar as evaluated in the Crossborder study, which include commodity price mitigation, grid security and economic development, would provide any significant value (if any at all) in reducing utility costs or in mitigating the cost shift that results from net metering.

The ability of rooftop solar systems in APS's service territory to reduce regional or national commodity prices for electricity and natural gas is too small to measure. Also, rooftop solar provides virtually no value in grid security because the vast majority of solar systems will not operate without power from the utility or during a grid outage, and even if they did, this purported benefit would only be enjoyed by the solar participant and therefore would provide no value or benefit to other customers. Economic development is an important objective, but it does not directly impact utility costs and rates. Therefore, from APS's perspective, it is not appropriate to include any of these items in an evaluation of rooftop solar from a ratepayer perspective. APS provides the following support for this position.

Economic development and jobs creation are desirable outcomes from virtually any investment in generation resources, whether those resources are rooftop solar, centrally located solar, or conventional generation. However, those impacts are not used in the setting of utility rates and therefore would not be relevant for an evaluation of the cost shifting from net metering. But if the economic development and jobs creation impact were to be considered more broadly, a proper analysis would include not only the jobs created by the solar installation industry, but would necessarily need to include jobs lost in other industries as a direct result of reduced household disposable income. The reduction in household disposable income is the effect of charging non-participating electricity customers more on their bills without increasing the level of services provided to them. A comprehensive analysis would then compare the net jobs gained, balanced against the net jobs lost (and the related income flows associated with these jobs), to assess whether the policy in question is a net benefit or net cost to the economy. To date, APS is not aware of this type of comprehensive study being performed for rooftop solar, and one is certainly not included in the Crossborder study.

The grid security benefits claimed by Crossborder typically pertain to lower occurrences of outages of rooftop systems compared with utility power plants; it also ascribes a benefit because (they assume) homes with rooftop solar retain power during a utility power outage. There is no evidence to support these claimed benefits and, if they were to exist, would chiefly benefit the solar homeowner and not be realized by other customers. As a result, non-participating customers should not be charged anything additional related to such a preceived benefit.

For example, the vast majority of rooftop solar systems installed on APS's system will not operate if the grid has an outage, due to the electrical safety requirements for interconnecting rooftop solar to the grid (UL requirement 1703). Furthermore, for those very few systems with battery back-up and interconnection equipment that allow the solar system to operate independent of the electrical grid, the purported security benefits would only pertain to grid outages that happened when the solar unit was operating. In any case, any resulting benefits, however small, would only be enjoyed by the solar homeowner and would provide no benefit to other customers. Additionally, like economic development, these purported benefits would not directly impact utility costs and rates, and therefore would not mitigate the cost-shifting from rooftop solar.

As for commodity price mitigation, the Crossborder claims appear to be highly improbable, and are a result of unproven suppositions and a flawed, incomplete analysis. As a general rule, APS can agree that increases in renewable energy are likely to have a downward impact on the demand for natural gas, and, as any good economics textbook makes clear, the expectation is that natural gas prices would be lower as a result of lower demand. But this is as far as the agreement can extend, for APS strongly disagrees with the magnitude of the price declines (and therefore the supposed benefits of displacing natural gas) suggested by Crossborder.

APS has several criticisms of the conclusions drawn by Crossborder on this topic. First, Crossborder in support of its concept, cites a study published by Lawrence Berkeley National Lab[1] ("LBNL") which estimates the impact on natural gas prices of increased

[1] Wiser, R., M. Bolinger and M. St. Clair. January 2005. *Easing the Natural Gas Crisis: Reducing Natural Gas prices Through Increased Deployment of Renewable Energy and Energy Efficiency*, Lawrence Berkeley National Laboratory.

renewable generation displacing natural gas generation. In particular, Crossborder cites LBNL's estimate of "gas bill savings... [which] range from $7.50 to $20 per MWh." However, Crossborder mistakenly assumes that this effect is related only to natural gas price changes, when in fact it also includes the volumetric effects of lower gas consumed in the production of electricity. This latter effect is clearly already captured in the avoided energy costs reported elsewhere in their study, leading to at least a partial double-counting of the effect. The LBNL study also counts as savings the potential impacts on consumers' natural gas bills, but in using US-level average consumption dramatically overstates the benefits to Arizona households who use, on average, less than half the natural gas annually as their counterparts in the rest of the country.

APS is critical of Crossborder's application of this study from a common sense perspective, as well. One of the figures included in the LBNL study (Figure 6: Forecasted Natural Gas Wellhead Price Reduction in 2020) clearly shows that the most extreme case of renewable generation displacing natural gas generation (an 800,000 GWh increase in renewable generation) yields less than a $0.60/MMBtu price change in the overall market for natural gas. By comparison, in the SAIC study, APS assumes that residential DG contributes an additional 2,000 GWh of renewable generation by 2025. If one assumes that the relationship between increased renewable generation and the market price of natural gas is linear (an assumption which is certainly implied by the LBNL graph), then at best we can expect to see a price change in natural gas related to increased DG that is 1/400th of $0.60/MMBtu, a value which would be impossible to see in the real market. This result makes sense. When the San Onofre Nuclear Generating Station was shut down in January 2012, it had the effect of removing 14,000 GWh of low-priced nuclear power annually from the market. If Crossborder is correct, this event should have had a substantial effect on natural gas prices. It didn't, however; the market absorbed the subtraction of 14,000 GWh with an imperceptible impact on natural gas prices.[2]

A third area of criticism relates to the market analysis performed in the Hoff, Norris and Perez (HNP) study cited by Crossborder. In this paper, flawed analysis has been used to substantiate a claim that is without foundation and does not pass the common sense test. The "analysis" performed in this paper develops a relationship between local area electric loads and locational

[2] See "Today in Energy", US Energy Information Administration, March 26, 2013. Pulled from http://www.eia.gov/todayinenergy/detail.cfm?id=10531.

marginal prices (LMPs) for those areas, then uses the change in load to predict a corresponding change in price. The local areas considered in this analysis include such cities as Scranton, Harrisburg, Pittsburgh, Jamesburg, Newark, Atlantic City and Philadelphia. On the surface, this may appear to be a helpful approach to getting at the question, but in reality, a little investigation reveals some deep flaws with the approach taken.

First and foremost, the correlations computed by HNP assume causation without allowing for other variables to be tested in the analysis. Secondly, the correlations are short-term in nature using conditions from only one year to derive a semi-permanent relationship with which to value future investments. Thirdly, the analysis is fundamentally flawed by ascribing all power price changes in a geographic area to load changes in that same area without any consideration for changes in factors which may affect power prices on a regional, national or even global level. This is most evident when one simply looks at the samples presented in the paper (see pages 40-41) and observes that perhaps as much as 98% of the relevant observations for any month are clustered along a relatively flat portion of the graph, with the remaining 2% (or so) of the observations being utilized to create an exponential relationship between changes in load and changes in prices.

Any legitimate analysis of wholesale power prices should attempt to control for changes in fuel prices, changes in infra-marginal generator availability and the applicability of transmission constraints before concluding that changes in load are responsible for changes in wholesale prices. There does not appear to be any attempt by HNP to include such factors in their analysis. In the absence of a more comprehensive analysis, one cannot place much reliance on the resulting equation because one does not know whether such conditions will persist into the future. If high LMPs are related to transmission constraints, then it may be that a transmission system upgrade will be the most cost-effective means of reducing congestion and eliminating price spikes within the local area. If a spike in natural gas prices caused power prices to surge, then an analysis of the drivers of natural gas prices would be required – and it is highly doubtful that a sudden increase in demand in Scranton or Harrisburg created a spike in natural gas prices. This would be akin to saying that a one dollar per gallon increase in the cost of gasoline (regionally or nationally) was the result of a sudden increase in demand for gasoline in Phoenix.

The resulting estimates do not seem plausible. In 6 of the 7 cities "evaluated" by HNP, the benefits from reducing wholesale market prices generally match or exceed the fuel and O&M costs avoided through the displacement of conventional resources with distributed solar generation. APS has decades of experience in serving the power demands of its customers, which includes responding to daily and hourly load changes, and can categorically submit that such a relationship between wholesale power prices and load levels does not exist. When power prices have escalated to exaggeratedly high levels in the past, the root cause of the move in prices has been system-related factors. These factors may have coincided with high load levels, but it was not the load levels themselves that caused the price response in the wholesale market.

Crossborder also claims that rooftop solar benefits other customers by lowering the utility's cost of complying with the renewable energy portfolio standard. The opposite is actually true for all compliance beyond the distributed generation carve out found in A.A.C R14-1805 (DG carve-out). Distributed generation is more expensive on a kWh to kWh basis than central (or utility-scale) solar. And because there is a finite amount of general REST compliance that is required, each compliance-related dollar spent on rooftop solar is a dollar not spent on central solar. Please see the Company's responses to Staff 1.32 and 1.34. Regarding compliance with the DG carve-out, any such claimed benefit is very low or zero at this time, because we are exceeding our current renewable requirements. In addition, this purported benefit would continue to be very low in the future as solar costs approach parity with natural gas generation, as claimed by solar companies.

For these reasons, APS does not believe the ancillary benefits described in the Crossborder study have any measurable value.

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Staff 1.5: Please provide a response to Crossborder Energy's criticism of SAIC's production cost modeling technique and the results obtained.

Response: The modeling technique used by APS is rigorous, and is routinely performed by major utilities and consultants in the industry. Nonetheless, Crossborder Energy appears to have two major criticisms with APS production cost modeling.[1] APS does not believe these criticisms have any merit.

1. Crossborder Energy states, "Although production cost results can be useful for short-term forecasting and budgeting, such tools have less relevance in projecting long-run avoided costs that focus on the costs avoided by not having to build or buy certain long-term resources."

Much to the contrary, production cost results are useful for projecting long-run avoided costs, and in fact these production cost results are used in several ACC accepted processes. PROMOD is the tool used to develop APS's Integrated Resource Plan, to calculate the avoided costs used in DSM cost effectiveness tests, and to calculate the long-run avoided costs used in evaluating renewable energy project bids.

A production costing model is necessary to determine the amount of coal displaced as well as the degree to which incremental heat rates from already operating gas plants are in effect. APS production cost modeling results also include costs associated with unit commitment decisions, which again, is an industry standard practice.

A primary strength of PROMOD is its ability to model APS's specific forecasted loads and generation resources on an hourly basis. It recognizes the dynamic nature of meeting daily and seasonal load profiles and the dynamic nature of solar production profiles, minimizing the cost to meet load and simulating the way the generation system is actually dispatched. Production cost modeling is an industry accepted practice used by all major utilities, and permits the development of costs based on known and measurable events. Without a production cost model such as PROMOD, one is left to simply make assumptions and run back of the envelope calculations, such as those employed by Crossborder. The method advocated by Crossborder would result in customers paying for hypothetical savings projections that are not consistent with other

[1] "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service", R. Thomas Beach and Patrick G. McGuire, May 8, 2013, page 4.

conditions likely to be observed in the future.

2. Crossborder also alleges that the SAIC Avoided Energy Costs are too low to be credible. This is simply not true. APS believes the avoided energy costs are credible. For example, production costs of coal and gas combined cycle generation are $25-$32/MWh in 2015. The result derived from PROMOD indicated an avoided energy cost of $30/MWh, well within the range of our marginal production units.

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Staff 1.6: Crossborder estimates the costs of commercial DG on APS' system to be between 9.2 to 11.5 cents and the costs of residential DG on APS' system to be between 19.9 to 20.5 cents. Crossborder then estimates a weighted average cost (13.7 cents) for all solar DG on APS' system, assuming the current mix of DG (44% residential versus 56% commercial) will persist in the future. Is it reasonable to assume the current DG mix will persist in the future given current trends? [e.g. 2012 and 2013 residential versus commercial installed capacity]

Response: No, it is not reasonable to assume a static 44 percent residential versus 56 percent commercial mix for incremental DG growth.

Crossborder sourced its DG mix assumption from the 2012 existing installation base from the SAIC study. The SAIC study was never intended or stated to be an expectation of the future installation mix. Crossborder sourced its 2015 total energy forecast directly from an SAIC study data file provided to all public technical conference stakeholders[1], and this same data forecasts residential energy as 54 percent of the cumulative DG mix in 2015, 70 percent of the cumulative DG mix in 2020, and 76 percent in 2025.

APS believes it is inappropriate to blend costs across both non-residential and residential classes. Nevertheless, by incorrectly understating the proportion of residential energy in APS's DE forecast, Crossborder calculates a significantly lower "cost of solar" than it would have if Crossborder had been consistent with its use of the SAIC study's data.

[1] Public data release file was titled "APS15189_DE Scenarios with Incremental Energy.xlsx".

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Staff 1.7: Since APS has limited its proposed net metering solution to residential DG, should we compare the 21.5 to 24.7 cents of benefits to the blended DG cost rate of 13.7 cents per kWh, or to the 19.9 to 20.5 cent cost estimate for residential solar DG?

Response: APS does not agree with the results of the Crossborder study, including the assertion that residential DG provides value that can be quantified at 21.5 to 24.7 cents per kWh. Nonetheless, Crossborder's results should be considered separately for residential and commercial (business) customers. In fact, APS is only proposing changes to the residential net metering program, so it would be misleading to consider data and results that are blended with other customer classes. Please note that the costs referenced by Crossborder are the cost shift; by using these costs, Crossborder is identifying the cost shift described by APS.

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Staff 1.8: Is it accurate to say that Crossborder estimates that APS realizes net benefits of 10 to 14.5 cents per kWh for commercial DG but only 1 to 3.8 cents per kWh for residential DG? If so, would the adoption of either of APS' proposed net metering solutions for residential customers have the effect of bringing the net benefits of future residential DG more in line with the net benefits of commercial DG utilizing Crossborder's analysis?

Response: APS does not agree with the Crossborder estimates. These estimates not only grossly exaggerate the conventional benefits of rooftop solar, such as avoided capacity and fuel costs, but also include a number of purported benefits that are highly disputed and irrelevant to utility rate impacts. It is also important to note that without these purported benefits, the residential class would fail the cost/benefit test, using Crossborder's own test, methodology, data assumptions, and estimates of costs and benefits. While APS does not agree with the methods, data, or results of the Crossborder study, the cited results in the question above do reflect Crossborder's estimates of the net benefits of rooftop solar and thus it is an accurate assertion that APS' proposals would bring Crossborder's net benefits for residential customers closer to their commercial results.

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Staff 1.9: How does DG change APS' ability to make off-system sales? How are these proceeds returned to APS' ratepayers/shareholders?

Response: A limited amount of DG displacement energy can be sold as off-system sales, and the margins on those sales are a fraction of the current net metering-based payment to customers with DG.

DG on the APS system either displaces purchases from the wholesale market or APS generation resources which are more economic than wholesale market purchases. Virtually all of the value of the displaced energy can be observed in the Company's calculation of avoided fuel expenses. However, there may be times when existing generation units have sufficient unused capacity and wholesale market prices are sufficiently high to allow for additional off-system sales, but these moments are expected to be rare. As a consequence of growth in DG systems, the Company's resource plan shifts more toward adding combustion turbines and away from baseload and intermediate generation resources, which quickly eliminates most of the opportunities for making off-system sales. The Company does not plan its system to enable it to speculatively make more off-system sales.

Furthermore, DG is an intermittent resource and does not have the same reliability or dispatch and operational characteristics of conventional resources. Under those rare circumstances when an economic APS generator is displaced, the displaced generation may be used to make off-system sales, subject to limitations from any increased operating reserve requirements stemming from the intermittency of DG.

The margins from any additional off-system sales are credited back to fuel expenses through the Power Supply Adjustment mechanism. Margins from off-system sales are typically less than 0.5¢/kWh.

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Staff 1.10: How does incremental DG affect the capacity needed for APS to satisfy its planning reserve margin requirement?

Response: Incremental DG does not affect APS's planning reserve margin requirement. APS' planning reserve margin requirements are calculated as 15% of system load net of firm purchases. In the APS Load and Resource Forecast, DG is modeled as a supply-side resource within the overall resource portfolio, designed to meet projected system loads and associated reserve requirements. It should be noted that as a supply-side resource, the dependable capacity of DG is equal to the product of its nameplate capacity (in MW) and its capacity value (in %), which is approximately 50% today and declines over time.

Based on APS' planning reserve margin percentage, Crossborder states that "each kW reduction in APS peak demand from DG will reduce the utility's capacity requirements by 1.15 kW" (page 10). This statement is incorrect since DG does not result in firm peak load reduction due to its variability and intermittency.

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Staff 1.11: Why does APS choose to discount future savings to ratepayers at the utility investors' discount rate, rather than a societal discount rate?

Response: When assessing the impacts of DG, the Company's cost of capital correctly reflects the level of risk associated with potential future net benefits due to both the lengthy time horizon over which these net benefits might be realized and the uncertainty about future technology costs and performance. Therefore, whether the perspective is taken from a utility point of view or a consumer point of view, the analysis leads to the utility cost of capital as the best proxy for discounting future costs and benefits.

It is important to note that the purpose of discounting is to estimate how much non-participants should provide *today* (at a maximum) as compensation to participants for benefits received in the *future* such that *non-participants* are *financially indifferent* (over the entire lifetime of the project) between someone deciding to install a distributed generation system and not doing so.

Simply put, discounting allows one to calculate how much non-participants should compensate participants such that their aggregate future electricity bills remain the same when measured in today's dollars. To assure adherence to the financial indifference principle, the choice of discount rate needs to reflect both the ordinary time value of money concept as well as the riskiness of the future cash flows (both costs and benefits). In this case, we are estimating future cash flows well into the future which indicates a need to use a discount rate that is more future oriented. (The term structure of market interest rates communicates how lenders require higher rates of interest the longer the term of the loan.)

Additionally, the cash flows associated with these future costs and benefits are not risk-free. The utility industry has been assessing future costs and benefits associated with conventional technologies for many years, and the risks to those potential cash flows due to unforeseen cost trends and/or technology performance issues are fairly well understood. Even so, there is some risk to these future cash flows. There is even more risk when the cash flows rely on a newer technology where the long-term performance is more uncertain than for more conventional technologies. As a consequence (and for other reasons), the discount rate chosen for determining financial indifference must be higher than the risk-free rate. And of course, the discount rate needs to be higher than expected inflation.

Given the time horizon and degree of risk associated with the future costs and benefits included in these studies, a long-term rate of return with a modest degree of risk is the appropriate choice for discounting those future costs and benefits. A blend of a utility debt rate (which tends to reflect low risk) and a utility equity rate (which incorporates a higher level of risk) appears to be a very good proxy for the overall level of risk embedded in these analyses.

Finally, as a practical matter, it would be difficult (if not impossible) to make a choice of a societal discount rate otherwise simply because there is a lack of consensus about what that rate ought to be – if it is to deviate from a purely financial basis. This lack of consensus is not surprising given that discount rates are collectively determined by individual circumstances and the population is rather heterogeneous. Some have argued that on ethical or moral grounds, the societal discount rate should be lower (potentially zero) than the market-observed opportunity cost of capital.

The trouble with this argument is that one must make determinations of what policies are appropriate for all consumers and what the right value is related to these policy choices.

Any discount rate different than the company's marginal cost of capital would *necessarily* be ignoring the financial indifference principle that underpins the standard discounting approach and would instead be subjectively determining financial winners and losers. Such a rate may also not capture and differentiate risk appropriately.

The Company believes the more appropriate policy is to set the discount rate at a level that adheres to the financial indifference principle and then allow policy-makers to overlay their policy preferences on top of the purely financial conclusions if they so choose.

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Staff 1.12: What load and resource forecast is used in the SAIC study? Please provide loads and resources anticipated for each future year (e.g. 2014 through 2025).

Response: **REVISED RESPONSE:**

The SAIC study used the APS 2012 Q4 Load and Resource Forecast. Attached as APS15245 are load and resource plans for the SAIC Base Case (assuming no incremental DG ~~above compliance~~ after 2012) and the Expected DG Penetration Case described in the SAIC Report (pages 2-3 and 2-4).

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2012 Q4 APS LOADS & RESOURCE PLAN
SAIC DG STUDY - EXPECTED DG PENETRATION CASE (In MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Requirements															
APS Peak Demand	7,131	7,396	7,567	7,835	8,145	8,448	8,751	9,044	9,343	9,648	9,948	10,244	10,541	10,841	11,146
Reserve Requirements	977	999	1,003	1,020	1,045	1,071	1,101	1,131	1,237	1,279	1,318	1,360	1,396	1,436	1,476
Total Resource Requirements	8,109	8,396	8,569	8,854	9,190	9,518	9,852	10,175	10,580	10,926	11,266	11,605	11,937	12,277	12,622
Existing Resources															
Existing Conventional Generation	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440
Existing Renewable Generation	48	43	41	39	38	37	37	36	36	35	34	32	31	31	31
Purchased Power Contracts	2,547	2,545	2,470	1,811	1,161	1,161	1,161	564	84	84	71	71	70	70	55
Total Existing Resources	9,035	9,028	8,951	8,289	7,639	7,638	7,637	7,040	6,559	6,559	6,544	6,543	6,541	6,541	6,526
Customer Resources															
Energy Efficiency	101	222	366	519	663	792	894	1,025	1,099	1,124	1,159	1,175	1,234	1,269	1,305
Distributed Generation	49	88	111	124	150	183	210	235	247	269	285	301	316	330	344
Demand Response															
Existing Demand Response	21	21	21	26	26	26	26	26	26	26	26	26	0	0	0
Future Demand Response	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
Total Customer Resources	171	331	497	669	839	1,026	1,181	1,386	1,497	1,569	1,645	1,702	1,774	1,849	1,924
Future Resources															
Natural Gas															
Combined Cycle	0	0	0	0	0	0	0	1,060	1,560	1,560	1,560	1,560	1,560	1,560	1,560
Combustion / Steam Turbines	0	0	0	0	102	204	408	408	408	612	918	1,122	1,326	1,632	1,938
Short-Term Market Purchases	0	0	0	0	198	238	213	0	134	206	154	210	246	204	165
Renewable Energy	41	361	388	413	413	413	413	412	421	420	445	468	490	491	510
Total Future Resources	41	361	388	413	713	855	1,034	1,880	2,523	2,798	3,077	3,360	3,622	3,887	4,173
TOTAL RESOURCES	9,246	9,720	9,836	9,372	9,190	9,518	9,852	10,306	10,580	10,926	11,266	11,605	11,937	12,277	12,622

2012 Q4 APS LOADS & RESOURCE PLAN
SAIC DG STUDY - BASE CASE NO ADDITIONAL DG AFTER 2012 (In MW)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Load Requirements															
APS Peak Demand	7,131	7,396	7,567	7,835	8,145	8,448	8,751	9,044	9,343	9,648	9,948	10,244	10,541	10,841	11,146
Reserve Requirements	977	999	1,003	1,020	1,045	1,071	1,101	1,131	1,237	1,279	1,318	1,360	1,396	1,436	1,476
Total Resource Requirements	8,109	8,396	8,569	8,854	9,190	9,518	9,852	10,175	10,580	10,926	11,266	11,605	11,937	12,277	12,622
Existing Resources															
Existing Conventional Generation	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440	6,440
Existing Renewable Generation	48	44	41	40	40	40	40	40	40	40	39	38	36	37	37
Purchased Power Contracts	2,547	2,545	2,470	1,811	1,161	1,161	1,161	564	84	84	71	71	70	70	55
Total Existing Resources	9,035	9,028	8,952	8,290	7,640	7,640	7,641	7,044	6,564	6,564	6,549	6,548	6,547	6,547	6,531
Customer Resources															
Energy Efficiency	101	222	366	519	663	792	894	1,025	1,099	1,124	1,159	1,175	1,234	1,269	1,305
Distributed Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response															
Existing Demand Response	21	21	21	26	26	26	26	26	26	26	26	26	0	0	0
Future Demand Response	0	0	0	0	0	25	50	100	125	150	175	200	225	250	275
Total Customer Resources	121	243	386	545	689	843	970	1,151	1,251	1,300	1,360	1,401	1,459	1,519	1,580
Future Resources															
Natural Gas															
Combined Cycle	0	0	0	0	0	0	0	1,060	1,560	1,560	1,560	1,560	1,560	1,560	1,560
Combustion / Steam Turbines	0	0	0	0	204	408	612	612	612	918	1,122	1,428	1,632	1,938	2,244
Short-Term Market Purchases	0	0	0	0	243	212	214	0	162	152	217	186	236	208	183
Renewable Energy	41	362	389	414	414	415	415	415	432	432	458	482	504	505	525
Total Future Resources	41	362	389	414	861	1,035	1,241	2,087	2,765	3,063	3,357	3,656	3,932	4,211	4,511
TOTAL RESOURCES	9,197	9,632	9,727	9,249	9,190	9,518	9,852	10,282	10,580	10,926	11,266	11,605	11,937	12,277	12,622

Staff 1.13: In the SAIC study, are fuel transport costs counted as fixed or variable costs? In rates, is this included in the energy portion of the bill?

Response: Fuel transportation costs are part of fixed O&M and considered a fixed expense. These costs are recovered along with other fuel related costs through kWh charges on the customer bill. Fuel transportation costs are typically fixed over a year, but can vary from year to year as related costs change.

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AUGUST 1, 2013

Staff 1.14: What is the confidence interval associated with APS's prediction of future load forecasts?

Response: From APS's 2012 Integrated Resource Plan, APS's weather-normalized load is expected to be with 80% confidence within +/-7% of the forecast produced five years prior and +/-9% of the forecast produced fifteen years prior.

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Staff 1.15: What is the confidence interval associated with APS's prediction of future natural gas prices?

Response: APS does not calculate a confidence interval associated with the forward natural gas curve. Rather, APS uses market prices derived from the New York Mercantile Exchange (NYMEX).

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Staff 1.16: Is the load shape utilized in the SAIC study consistent with APS's prediction of near-term changes to that load shape (as created by increased DG penetration)?

Response:

Yes, the system and DG load shapes utilized in each of the three penetration scenarios included in the SAIC study are consistent with APS' prediction of near-term changes affecting them due to increased DG penetration.

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Staff 1.17: How will assumptions about APS' planned resource mix affect the marginal cost of power?

Response: APS employs PROMOD, a production cost model widely recognized and used in the electric utility industry, to estimate the marginal or avoided cost of power. The planned resource mix is only a component of the marginal cost estimation process. The nature (size and shape) of the load to be displaced, e.g., DG and EE, and the marginal costs of existing generation technologies, such as coal and combined cycle generation, will ultimately determine the mix of displaced energy, and consequently the marginal cost of power.

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Staff 1.18: Why did the SAIC study choose to use the average system line losses instead of a marginal value as utilized in the Crossborder energy study? Is the Crossborder study approach appropriate and accurate?

Response: Average line loss rates were the closest estimate of what the real impacts on transmission and distribution system losses are when taking into account times when DG systems are over-producing relative to customer load and times when they are not producing at all.

Because the studies filed with the Commission are attempting to quantify the benefits from DG deployment, where possible, the assumptions that are used should be ones that have some empirical validation.

The average system line loss used in the SAIC study is empirically verifiable, previously reported and utilized in the IRP process, whereas the marginal analysis adopted by Crossborder relies on a simplistic, static, theoretical assumption. APS has simply not observed such high marginal losses on its system.

Given the dynamic, real-world nature of the electrical system, and inherent difficulties with accurately measuring marginal losses, it is inappropriate to assume the marginal losses are merely double the reported average losses without providing empirical support.

Other utilities are having trouble substantiating loss values as high as those used by Crossborder, as well. In a recent study[1] prepared by Xcel Energy Services to address the costs and benefits of distributed solar photovoltaic generation ("DG", or "DSG" in Xcel's parlance), Xcel concluded that average line losses were the most appropriate measure for grossing up energy differences due to DG and noted that "when a customer's generation exceeds twice his load, line losses on the customer's service drop exceed what they would have been with no generation. Because line losses increase with the square of net load, line losses increase at ever increasing rates with greater levels of DSG electricity production."[2]

In summary, Xcel found that there are times when avoided marginal line losses are greater than, less than, and approximately equal to average line losses.

[1] "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System: Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223", Prepared by Xcel Energy Services, Inc, May 23, 2013.
[2] *Ibid.*, p. 36.

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Staff 1.19: Why did the SAIC study choose to utilize a 13-year "snap-shot" study period versus a 20-year timeframe?

Response: In 2009 R.W. Beck prepared the "Distributed Renewable Energy Operating Impacts and Valuation Study". The parameters of that study were developed, decided upon and supported through a collaborative stakeholder process. The SAIC study updated the jointly developed and industry supported 2009 study. Years 2015 and 2025 were chosen for consistency with the R. W. Beck study and Year 2020 was added upon request by stakeholders participating in APS-sponsored technical conferences. The SAIC study was not based on a 13-year "snap-shot". It used a traditional 20-year forecast of loads and resources with various projected DG deployment scenarios as the source of fuel and capacity costs in conjunction with a detailed review of transmission and distribution plans for the specific years. The assessed years were either requested by stakeholders or chosen for consistency with the previous jointly supported study.

Also note that the twenty-year levelized benefit approach employed by Crossborder abandons the jointly developed parameters set by industry stakeholders. One reason APS believes this approach is inappropriate is because it only attempts to monetize a long-term value for a limited amount of DE solar installed in 2014. It does nothing to demonstrate the effects of increasing solar penetration on the APS system such as declining capacity value of solar.

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Staff 1.20: Please provide a response to the Crossborder Energy's criticism of SAIC using "blocks" of solar resources to determine capacity value

Response:

Crossborder Energy's criticism of SAIC using "blocks" of solar resources to determine capacity value is unjustified and biased in favor of its own methodology. Crossborder Energy assessed the 20-year benefits of DG as a single, one-time installation in 2014 (Table 1, page 2) and assumed that (1) there is a capacity deferral in 2014 regardless of APS's existing resource adequacy, and (2) the capacity value of DG does not change with DG penetration.

APS estimated the capacity value of DG as a separate resource, apart from EE and DR, because these 3 resources are quite different by their nature and thus have their own values. Combining them together in assessing their combined capacity value and early capacity deferral opportunity is misleading in the search for the true value of DG in the APS system.

SAIC's "blocks" approach to estimate DG capacity value is technically sound and superior because it takes into account (1) the long-term planned DG deployment schedule over APS's 20-year planning horizon (the amount of installed DG is projected to increase annually), and (2) annual DG penetration (DG capacity vs. APS system peak demand), which affects its annual capacity value because higher DG penetration results in lower capacity value.

Staff 1.21: Please provide your estimate of the ancillary benefits of renewable DG noted in the Crossborder study, including price mitigation, grid security, and economic development. Provide a discussion of how these benefits are quantified and your assessment of the value of these benefits.

Response: Please refer to the response to Staff 1.4.

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Staff 1.22: What dollar value do you ascribe to the environmental benefits (i.e. reduced CO_2, SO_2, NO_X, and PM_{10} emissions, and less water consumption) of solar DG?

Response: To the extent that environmental benefits provided by solar DG can be quantified, they are already included in APS's avoided cost calculations.

Specifically, environmental benefits used in the SAIC study are those utilized in the 2012 APS IRP filing and are listed below:

	CO2 (in $/Metric Ton)	SO2 (in $/Ton)
2015	0.00	2.05
2020	15.72	2.43
2025	22.56	2.94

These CO_2 values assume that federal carbon tax legislation becomes effective beginning in 2019. This assumption and the stated values are based on an analysis of legislative attempts to enact carbon tax legislation that Charles River Associates conducted for APS in connection with APS' 2012 Integrated Resource Plan. If a federal carbon tax does not materialize, the value for CO_2 would be zero.

SO_2 values are estimates based on market trading activity and are included in avoided energy costs.

Benefits for avoiding NO_X control costs are included in avoided capacity costs.

Benefits associated with water reduction are included in avoided energy costs.

APS does not explicitly add costs for externality values such as PM_{10}.

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Staff 1.23: Please provide a rationale for how the capacity losses value of 11.7% (SAIC presentation April, 2013, Slide 59) was determined?

Response: The capacity/peak demand loss value of 11.7% is based on the demand loss used in APS's 2010 Cost of Service Study. The attached document APS15247 provides the breakdown of losses from the generation source all the way to the customer meter.

ARIZONA PUBLIC SERVICE COMPANY
Line Loss Values Used in Allocation Factors
Cost of Service Study - Test Year Ending 12/31/2010

Demand Line Losses

Customer Meter 120/240	1.05002	Secondary Side of Distribution Transformer 12 KV	1.00373	Primary Side of Distribution Transformer 12 KV	1.02013	Secondary Side of Substation Transformer	1.00945	Primary Side of Substation Transformer	1.01261	Primary Side of 230/69 KV Transformer	1.01712	Generating Station	11.78%	Total Demand Line Loss (Multiplicative)
	Losses thru Service Drop & Service Entrance		Distribution Transformer Losses		Distribution Feeder Line Losses		Distribution Substation Transformer Losses		230/69 KV Transformer Losses and 69 KV Transmission Line Loss		Step-up TXF Loss @ Plant, 500 KV Transmission Loss, 500/230 KV Step-down TXF Losses, and 230 KV Transmission Loss			

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Staff 1.24: How is the customer's capital investment valued in the SAIC model?

Response: The customer's investment cost or leasing cost for rooftop solar is not directly evaluated in the SAIC study or in APS's overall assessment of rooftop solar because the objective of the assessment was to evaluate the impact of rooftop solar on utility costs and rates. The customer's cost would not have any direct impact on rates and, therefore, is not relevant to the study.

While the customer's out-of-pocket cost would be relevant for a total resource cost test or a societal cost test, which evaluates the resource costs incurred by the utility, participating customers, and other parties, it is not germane to a rates assessment, which, again, only evaluates the cost and revenue impacts.

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Staff 1.25: How are O&M costs of customer-sited DG valued in the SAIC model?

Response: The solar customer's O&M costs were not evaluated in the SAIC study for similar reasons provided in response to Staff 1.24.

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Staff 1.26: Please provide a response to Crossborder Energy's criticism of SAIC's production cost modeling technique and the results obtained.

Response: Please see response to Staff 1.5.

Staff 1.27: Please provide a response to the production cost modeling methodology utilized in the Crossborder study.

Response: APS uses a rigorous and detailed production cost modeling process to determine the disposition of avoided energy due to DG. APS's production cost model determined that the avoided energy would actually be 36% coal, 63% combined cycle, and 1% combustion turbine for year 2015. Crossborder simply assumed that it would come from a combustion turbine in the summer months (33% of the time), and a combined cycle in the non-summer months (67% of the time).

The simplistic method employed by Crossborder significantly overstates the levelized avoided energy cost due to solar DG. They calculate a twenty year levelized value and imply that APS solar customers should be compensated for that value today, even though that value is dependent on many future assumptions that may or may not happen (such as carbon legislation) and that value may never be realized. See also APS response to Staff 1.2.

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Staff 1.28: What is annual revenue APS receives from its residential solar customers?

Response: For calendar year 2012, the annual revenue received from residential rooftop solar customers was $9.6 million.

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Staff 1.31: Describe the usage profile of a typical residential DG customer.

Response: The usage profile of a typical residential solar customer depends on their profile prior to installing solar as well as how much solar they install.

Solar customers typically have above average usage prior to installing solar; most live in medium and large homes versus small homes or apartments. APS believes that the time-of-use-energy (TOU-E) rate class information provides a reasonable estimation of a solar customer's usage profile prior to adding solar because the average TOU-E customer has a similar monthly kWh usage as solar customers and the majority of solar customers are served under a TOU-E rate.

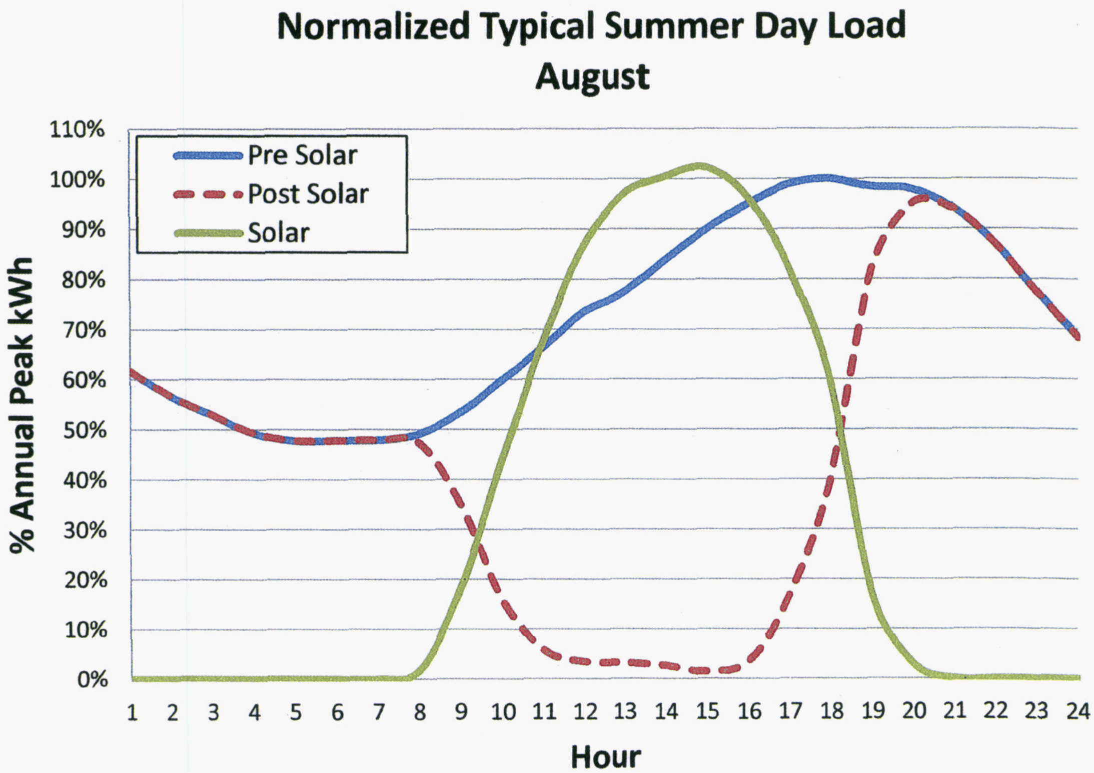
The estimated pre-solar usage profile for the typical solar customer has the following characteristics: average monthly usage of 1,250 kWh, 1,600 kWh per summer month (May-Oct) and 900 kWh per winter month (Nov-April); average monthly kW demands (maximum hourly load) of 6.2 kW, 7.2 kW for summer months, 5.2 kW for winter months.

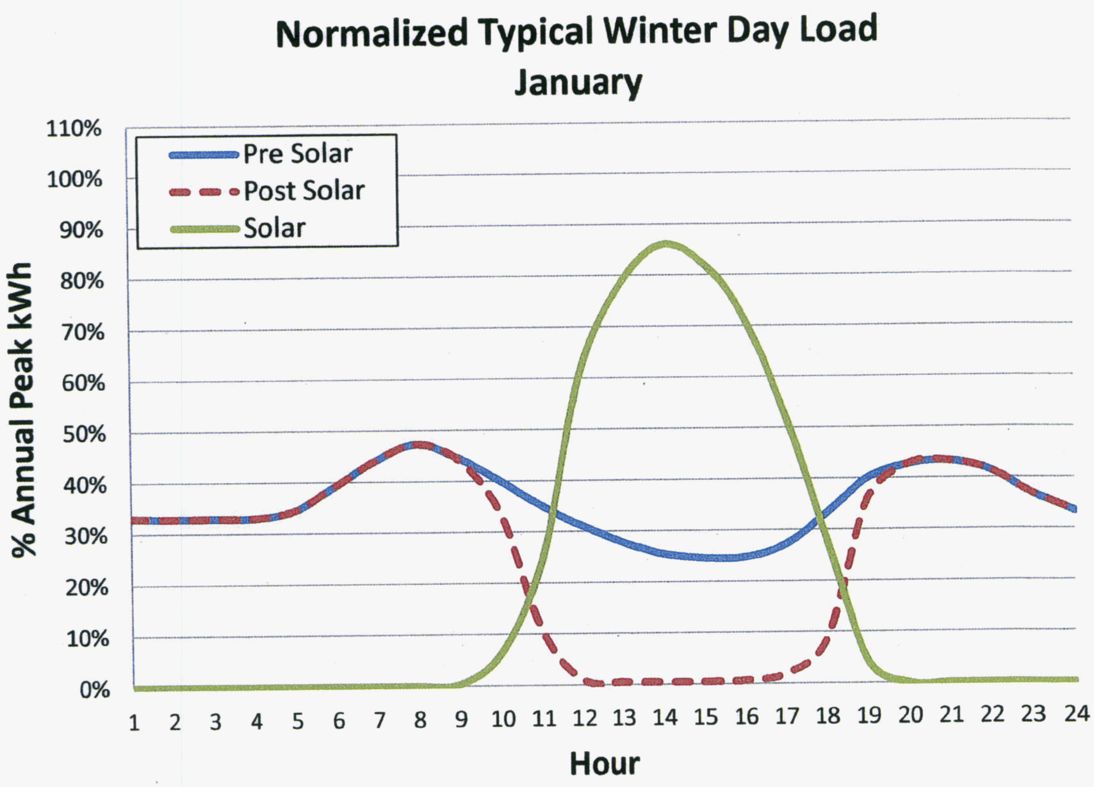
APS estimated the monthly usage profile with solar by subtracting the typical solar generation profile from the pre-solar usage. The resulting usage profile, with solar, has the following characteristics: average monthly usage of 422 kWh, 638 kWh per summer month (May-Oct) and 206 kWh per winter month (Nov-April); average monthly demands of 5.6 kW, 6.5 kW for summer months, 4.7 kW for winter months, assuming solar reduces monthly billing demand by 10%.

The hourly load profile for a typical solar customer, both before adding solar and after adding solar, are depicted below for representative winter and summer months. These load profiles are normalized to the peak load hour of the year to provide a better relative description of the daily and seasonal usage trends. As shown, in the summer, the pre-solar usage is relatively low in the morning, builds during the day, peaks between 4 pm and 8 pm, remains relatively high through 10 pm and then drops off through the night.

After adding solar, the load is unaffected in the early morning, is reduced dramatically during the day due to the offsetting solar production, increases significantly after 4 pm as the solar production tapers off and the household load increases, peaks at roughly 7-8 pm when the household usage is high, but the solar production is zero or extremely low, remains relatively high through 10 pm and then decreases through the night. While the kWh energy usage is reduced significantly with solar, the household peak kW usage in the late afternoon to early evening hours is only reduced by a few percent and shifted a couple of hours later.

For winter months, the customer's pre-solar overall usage is significantly lower than in the summer. It peaks from 7 am to 9 am in the morning, is lower during the day and peaks again from 7 pm to 10 pm in the early evening. Solar generation reduces the mid-day usage, but does not reduce either the morning or early-evening household peaks.




Normalized Typical Winter Day Load
January
Pre Solar
Post Solar
Solar
% Annual Peak kWh
110%
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
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Staff 1.32: APS asserts that it could build equivalent sized solar resources at a lower cost than a similar-sized aggregation of customer-owned and sited DG. Please provide documentation (actual RFP proposals or service offers) to support this assertion.

Response: APS estimates that the wholesale market price for utility-scale solar resources that can be interconnected at the distribution level is in the range of 7 to 9 cents/kWh, which is much lower than the current cost to APS customers of funding residential DG of between 13 and 14 cents/kWh on a pre-tax basis. APS bases this estimate on several factors:

1. APS's most recent solicitation for 3rd-party-owned utility-scale resources yielded an average PPA price of between 9 and 10 cents/kWh. This solicitation was conducted in the first half of 2011, more than 2 years ago. Price information received during the RFP process is competitively confidential and is provided to Staff pursuant to an executed Protective Agreement.
2. In March 2013, APS contracted with a 3rd party to construct the Gila Bend Power Plant, a 32 MW solar photovoltaic facility, at an installed cost of less than $[redacted]/Watt. This figure translates into a cost of approximately [redacted] cents/kWh, which reflects the downward trend in solar PV pricing. This installed cost is consistent with the installed costs observed by SEIA for utility-scale solar during that same time period.[1] Pricing and documentation for this contract is competitively confidential and is provided to Staff pursuant to an executed Protective Agreement.
3. In its recent Renewable Auction Mechanism (RAM) process, the California Public Utilities Commission cited solar PV pricing at 8.4 cents/kWh. Please see page 11 of the attached APS15250, a California Public Utilities Commission presentation made at the 2012 National Summit on RPS.

In sum, there are a variety of sources confirming that the current cost for utility-scale solar resources is considerably below the cost of funding residential DG through the current net metering policy.

[1] US Solar Market Insight, 2013, Green Tech Media, Inc. and Solar Energy Industries Association (SEIA).

Renewable Auction Mechanism (RAM):

New Procurement Tool for Distributed Renewable Generation

2012 National Summit on RPS

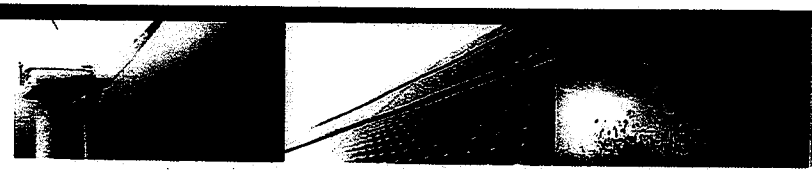
Presented by Paul Douglas

California Public Utilities Commission

December 4, 2012

Why Pursue DG Procurement Strategy?

- In between the RPS program and the customer-side DG programs (e.g., California Solar Initiative) is a potentially vast, untapped market segment for system-side renewable DG. Benefits of this market segment include:
  - Quick project development timelines
  - Avoidance of new transmission
  - Declining technology prices
  - Insurance for riskier, large-scale renewable projects



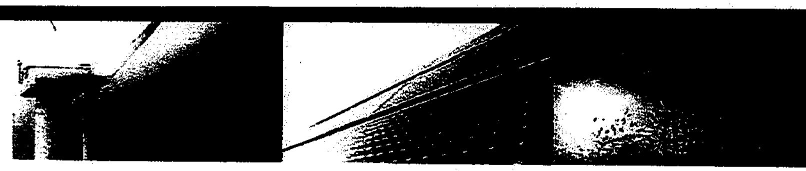
Guiding Principles for DG Procurement

Operating Assumptions:

- Sufficient number of developers in the DG market segment to ensure competition.
- Projects greater than 20 MW would participate in RPS solicitations

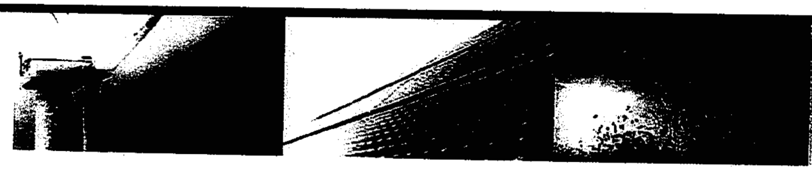
Guiding Principles for DG program:

- Identifies least-cost viable projects that can interconnect quickly
- Creates a sustainable and long-term market for system-side renewable DG projects
- Provides sufficient payment to simulate untapped market segments at the distribution level while preserving competition
- Minimizes the transaction costs for the seller, buyer, and the regulator
- Equitably allocates risk between the buyer and the seller
- Adequately addresses project viability



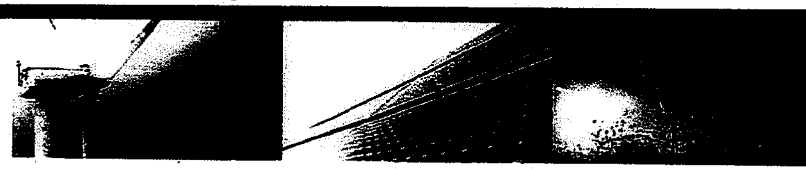
RAM Snapshot

- **Basics:** a simplified, market-based auction mechanism designed by the CPUC to procure cost-effective, viable renewable projects up to 20 MW
- **Viability:** Projects must pass binary viability screens to participate – site control, developer experience, commercial technology, interconnection study results
- **Timely MWs:** Must be online within 2 years of CPUC approval
- **Program Duration:** 4 auctions over two years (2011-13)
- **Program Size:** 1,299 MW
- **Eligible Project Size:** From 3 MW up to 20 MW
- **Product Types:** Baseload, Peaking, Non-Peaking
- **Procurement Targets:** IOU-specific targets per RAM auction



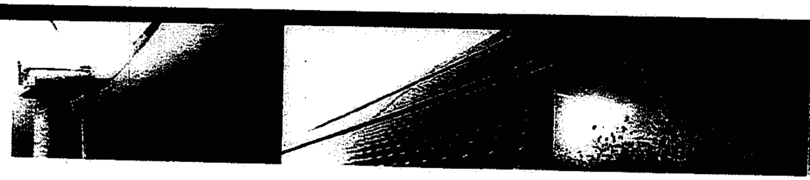
Project Viability Screens

- Seller must meet minimum criteria to participate in the auction in order to lower risk of contract failure
  - **Site Control**: 100% site control through (a) direct ownership, (b) lease or (c) an option to lease or purchase that may be exercised upon award of a RAM contract
  - **Development Experience**: One member of the development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project
  - **Commercialized Technology**: Project is based on commercialized technology
  - **Interconnection Study**: Bidder must have received results from its first interconnection study (system impact study or phase I cluster study)
- Projects have 24 months to achieve COD + 6 month option due to regulatory delays



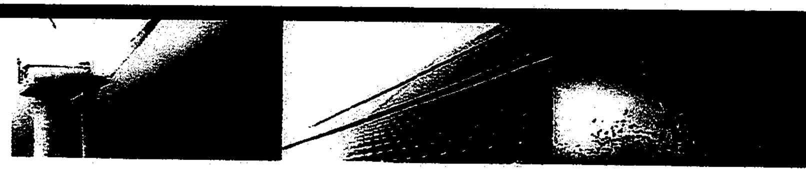
Market-Based Pricing

- Seller develops bid price that reflects cost to build a project and provide a return on investment
- Bids are selected on price plus transmission upgrade costs
  - Staff modified RAM2 to allow the utilities to take into account resource adequacy value
- Products with similar characteristics are compared to each other
- Lowest cost (highest value in RAM2) projects are selected until the auction capacity cap or revenue requirement cap is reached
- Bid price is not negotiable and is <u>paid as bid</u>



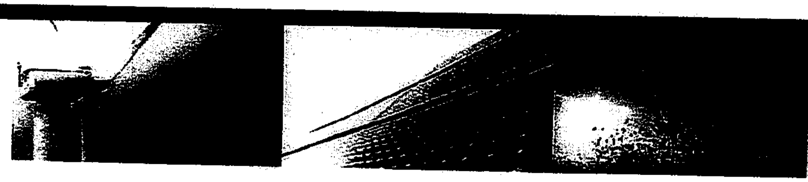
Standard Contract

- CPUC adopted a standard, non-negotiable contract for each IOU
  - Each IOU drafted their own contract, which the CPUC modified based on stakeholder comments
- Decision requires certain terms to ensure there is "skin in the game":
  - 24 month online date
  - Project development deposit
  - Performance deposit

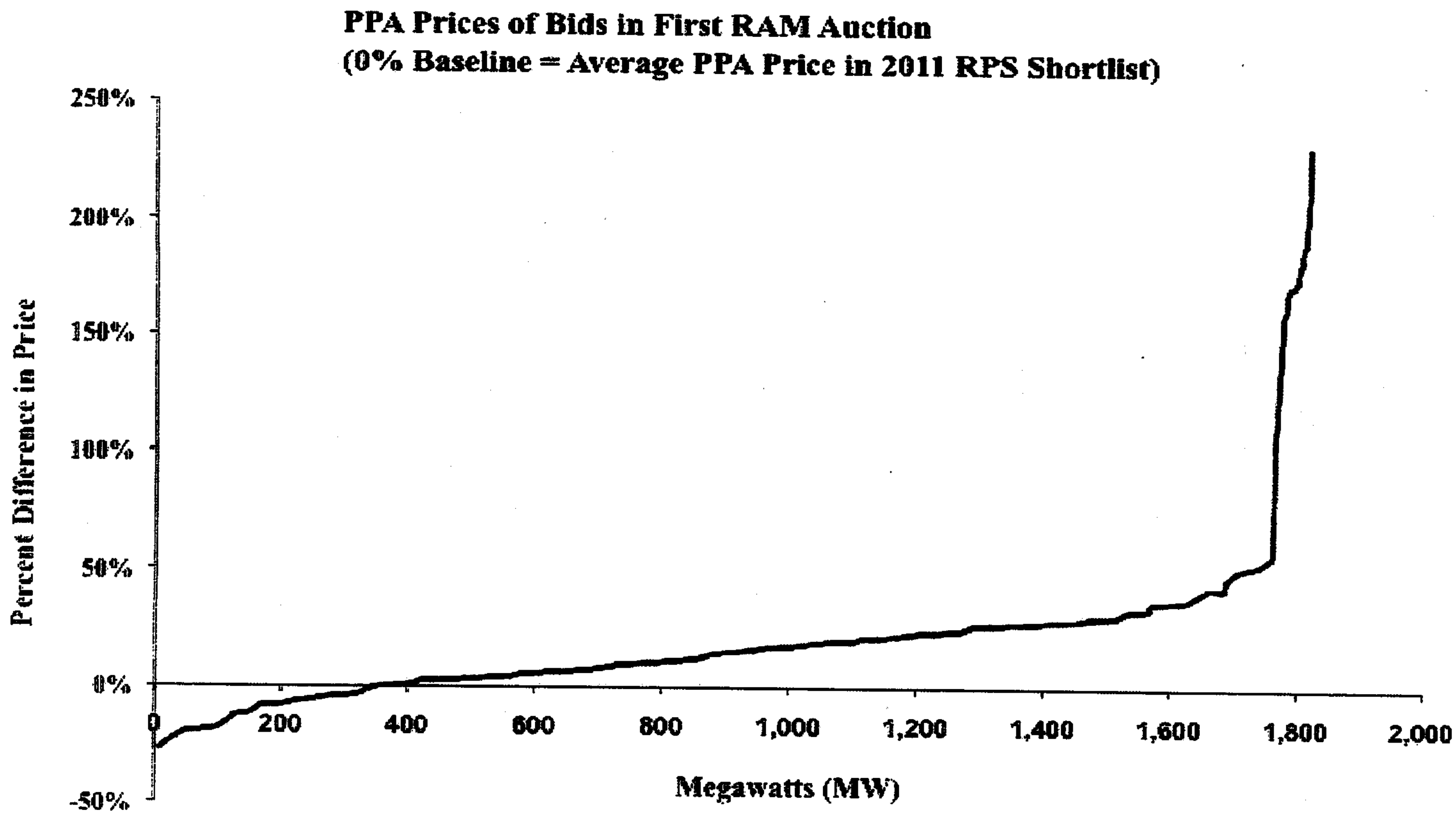


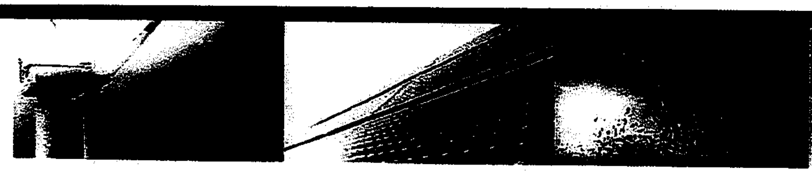
Overview of RAM1 and RAM2 Results

- **Robust Competition:** California's utilities set procurement targets totaling 568 MW for RAM1 and RAM2 – bids representing 10x more capacity than the utilities targeted bid into these auctions.
- **High Value:** The most competitive bids from both RAM1 and RAM2 came in below $90/MWh (post-TOD). The average bid price and the average price of executed PPAs fell ~5% from RAM1 to RAM2.
- **Technology Diversity:** Over 90% of bids into both RAM1 and RAM2 were for Solar PV projects, but participation of non-solar projects in RAM2 increased 3x over RAM1.
- **Viable Projects?:** Too early to tell. Projects from RAM1 are scheduled to come online by Q4 2013, and projects from RAM2 by Q4 2014.



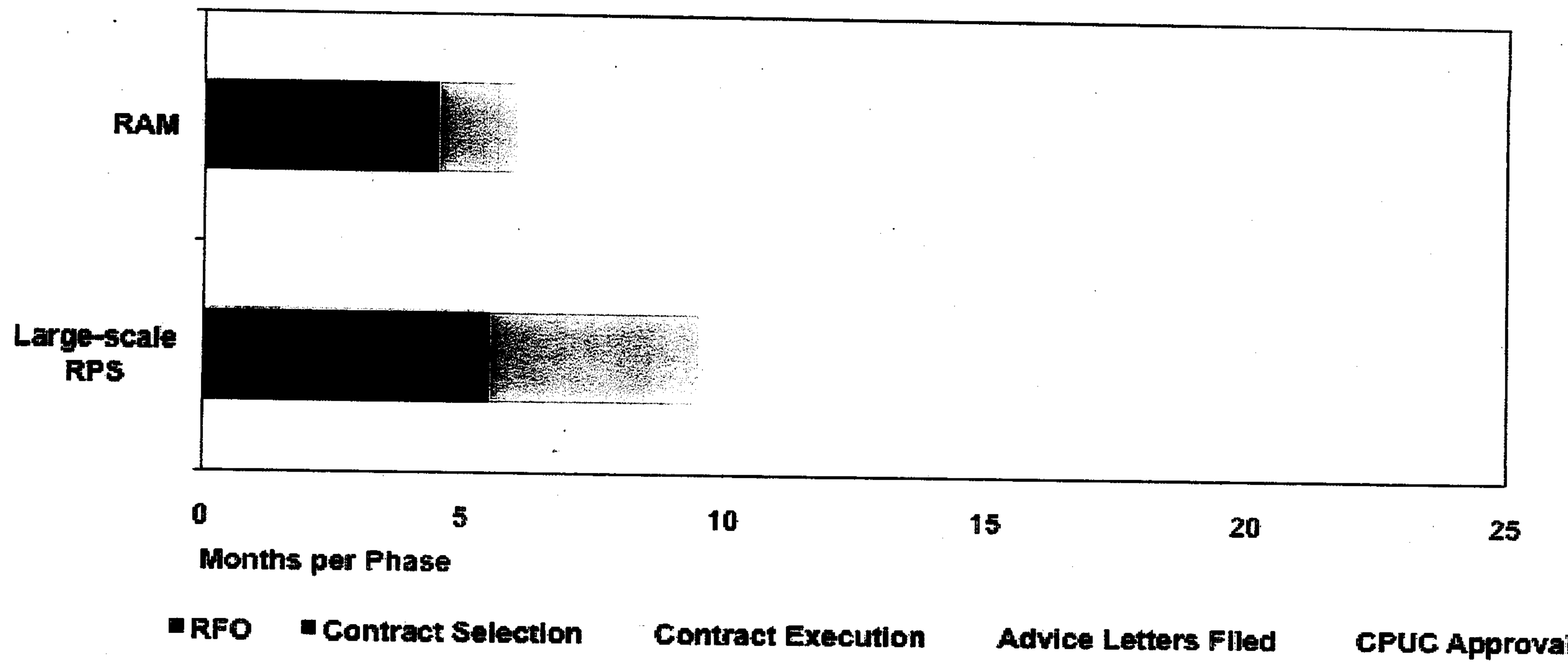
RAM Bid Prices Competitive Compared to 2011 RPS Solicitation

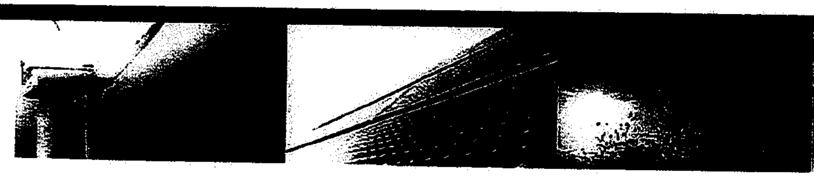




RAM Procurement is approximately 3 times faster than RPS Solicitation

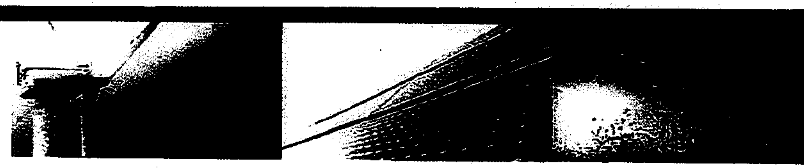
Estimated Timelines for RAM vs. Large-Scale RPS RFO:
From Bid Solicitation to CPUC Approval





Conclusions

- **<u>Competitive.</u>** RAM continues to attract robust market participation, resulting in PPA prices below $90/MWh.
  - **RAM1:** $89/MWh **RAM2:** $84/MWh
- **<u>Larger Projects.</u>** As a percentage of bids and of executed PPAs, RAM2 skewed in favor of projects in the 15 to 20 MW size range.
- **<u>Solar PV Dominant.</u>** The same as RAM1, Solar PV projects comprised the overwhelming majority of both bids and PPAs.
- **<u>Positive Feedback.</u>** Developers responded positively at RAM program forums to the policy changes implemented for RAM2 (extended COD + created energy-only bidding option), and Utilities continue to express their general support for the simplicity and effectiveness of RAM for renewable procurement.



More Information

CPUC RPS Website:
- www.cpuc.ca.gov/renewables

CPUC RPS RAM Website:
- http://www.cpuc.ca.gov/RAM

IOU RAM Website:
- SCE: http://www.sce.com/EnergyProcurement/renewables/renewable-auction-mechanism.htm
- PG&E: http://www.pge.com/rfo/RAM/
- SDG&E: http://sdge.com/procurement/rfp-and-rfo/may-2012-renewable-auction-mechanism

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Staff 1.33: APS asserts that it can install solar PV (via utility ownership or PPA) on the subtransmission grid and produce all the same benefits estimated for solar DG in the Crossborder study at a lower cost than it would pay for the same capacity of solar DG. Please provide documentation (actual RFP proposals or service offers) to support this assertion.

Response: See APS Response to Staff 1.32.

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Staff 1.34: Please explain why such systems will produce the same benefits as customer-sited solar DG.

Response: APS believes that a utility scale solar purchased power agreement located at or near one of our load centers would provide virtually the same or more benefits as rooftop solar. Therefore, the PPA cost should serve as a ceiling for any claims or calculations of the benefits of rooftop solar. A detailed explanation is provided in Attachment APS15251.

Staff 1.34
Attachment

APS Net Metering Assessment
Comparison of Benefits of Rooftop Solar Vs. Central Solar

The benefits of rooftop solar were discussed in the recent technical conferences on distributed generation. Rooftop solar companies submitted a study by Crossborder Energy that evaluated those benefits from their perspective. APS submitted a study by SAIC that evaluated the benefits from its perspective.

There were many disagreements in the types and levels of benefits between the two studies. However, APS believes the long-run levelized cost of a central solar generator[1] should serve as an upper limit for any claimed benefits of rooftop solar because the central solar generator would provide virtually the same benefits and quite likely some additional benefits as well.

Below is a summary of the comparative benefits of central solar versus rooftop solar. The discussion is provided in three sections: (1) benefits that were generally agreed to in principle, but not in magnitude by APS and rooftop solar companies, (2) benefits claimed by rooftop solar companies, but disputed by APS, and (3) external social benefits that do not directly impact current utility rates.

BENEFITS OF ROOFTOP SOLAR GENERALLY AGREED TO BY SOLAR COMPANIES AND APS

Power Plant Capacity: Central solar likely provides a higher power plant capacity benefit

- Central solar would provide the same (or more) savings in the capacity costs for conventional generation compared to rooftop solar. No matter how the conventional generation is valued – which power plant is avoided, which year the plant avoidance begins, how much of the plant's capacity can be offset through solar– central solar would provide as much or more value of avoiding conventional generation as rooftop solar.

- Central solar may provide a higher value for this benefit because the generator's location and orientation can be optimized for better solar performance than rooftop solar and can include tracking technology that increases capacity value.

- Central solar would also more likely to have a tracking system compared to rooftop solar and therefore provide a higher capacity value.

[1] Central solar refers to utility scale solar in general which is independent of the ownership model.

- The central solar generator may also provide a higher value because it could be located in an area with transmission constraints, which would help avoid the construction of local generation. Conversely, because APS does not direct which customers install rooftop solar, rooftop solar does not provide this potential benefit. Conceivably, upfront incentives for rooftop solar could be increased in transmission constrained areas to address this issue. But this would only further increase the cost of rooftop solar compared to central solar, unless the incentives in other areas were reduced, or unless rooftop solar was only allowed in targeted areas. In any case, neither of these conditions are part of the current net metering program or proposed by any of the parties.

- In addition, central solar agreements have contractual performance requirements with guarantees or penalties which increase the expected value of avoiding conventional generation compared with rooftop solar.

Fuel: Central solar and rooftop solar provide comparable fuel benefits

- Central solar and rooftop solar would provide virtually identical benefits in avoided fuel costs from conventional generation because they both offset conventional generation.

Variable O&M: Central solar and rooftop solar provide comparable benefits

- Central solar and rooftop solar would provide virtually identical benefits in reduced variable O&M costs because they both offset conventional generation.

Fixed O&M: Central solar likely provides a higher fixed O&M benefits

- Central solar and rooftop solar can potentially defer fixed O&M costs from conventional generation. The benefit is likely to be higher for central solar than rooftop solar for similar reasons discussed in the power plant capacity benefit.

Water: Central solar and rooftop solar provide comparable water benefits

- Central solar and rooftop solar would provide virtually identical benefits in reduced water costs associated with the avoided conventional generation. Water costs are typically included in the variable O&M costs.

Transmission: Central solar likely provides higher transmission benefits

- Central solar would provide as much or more value from delaying the investment in new high voltage transmission lines compared with rooftop solar.

- Central solar generator could be located within or very near a load center (e.g. phoenix metro area). If so, central solar could reduce the cost of transmitting the power from remote power plants to the load center.

- Central solar can provide a higher value for this potential benefit compared with rooftop solar because of the higher capacity value discussed in the generation plant issue, and because the generator is more likely to be located to relieve transmission constraints.

Line Losses: Rooftop solar provides a modestly higher line loss benefit

- Rooftop Solar would provide a somewhat higher value of avoided line losses compared with central solar. Central solar would avoid the line losses from the remote conventional generator to the load center or distribution substation; rooftop solar would further avoid the line losses from the load center to the home. This difference would be a modest value – APS's average system line losses are approximately 7%, while the losses from the generation site to a distribution substation are roughly 3%.

Environmental Benefits: Central solar and rooftop solar provide comparable environmental benefits

- Solar generation can reduce APS's costs for complying with environmental regulations. These costs would include the current and expected environmental regulations associated with the conventional generation that solar power would reduce, which is a natural gas generating plant.

- In general, central solar would be expected to provide the same environmental benefits as rooftop solar because they both would offset the same type of conventional generation.

PURPORTED BENEFITS OF ROOFTOP SOLAR
CLAIMED BY SOLAR COMPANIES AND NOT SUPPORTED BY APS

Fuel Hedge: Central solar likely provides higher fuel hedge benefits

- Because solar generation reduces APS's fuel costs, it reduces the exposure to future changes and variability in cost of natural gas. For APS, this benefit is minimal, at best, because APS already manages a successful fuel hedging program and the amount of solar generation in question is small in relation to the amount of natural gas required to meet the needs of APS's customers.

- To the extent a fuel hedge benefit exists, it is already captured in the avoided fuel costs discussed above. Therefore, any additional fuel hedge value would be double counting this benefit. Any further related benefits beyond avoiding the future price of natural gas would amount to paying for insurance that is over and above what is provided today.

- However, in any case, central solar would provide the same purported fuel hedge benefit, or more, as rooftop solar because they both avoid the same amount of fuel. In fact, this benefit, if any, could be higher for central solar because the contractual obligations and penalties would make the fuel hedge more certain compared with rooftop solar, which typically does not have any performance guarantees to the utility.

Renewable Portfolio Standard

- Rooftop solar companies claim that when a customer installs rooftop solar they help to fulfill the renewable portfolio standard and thus reduce the cost of the standard for others. Therefore, other customers must contribute to the cost of their solar system and/or subsidize their power bill.

- APS does not necessarily agree that this is a legitimate benefit of rooftop solar. But in any event, APS is currently ahead of pace for complying with the standard, so any purported benefit would be zero at this point.

- However, if one agrees with this benefit, central solar would likewise contribute to meeting the renewable portfolio standard and therefore provide the same benefit as rooftop solar.

Wholesale Commodity Prices

- Rooftop solar companies claim that rooftop solar lowers the demand for electricity and natural gas and therefore lowers the regional market clearing prices for these commodities – not just for amount of solar generation, but for all of the electricity and natural gas purchased by the utility.

- APS does not believe that this is a legitimate benefit of rooftop solar for reasons provided in response to Staff 1.4. Also, using the same reasoning, when a customer purchases rooftop solar they would increase the demand and the market price for solar panels, not just for their home but for all solar panels, and therefore increase the cost of solar generation overall. This negative impact would thus have to be subtracted from any benefit of value of rooftop solar.

- However, if one agrees with this benefit, central solar would likewise reduce the utility's purchase of electricity and natural gas and therefore provide the same benefit (if any) as rooftop solar.

Distribution

- Rooftop solar companies claim a small benefit in avoided distribution infrastructure costs. APS believes that rooftop solar would typically not result in any reductions in distribution costs because the grid is designed to meet a peak neighborhood load, which for residential customers occurs in the early evening when solar production has dwindled down to zero. Rooftop solar could only theoretically provide a very small benefit in distribution costs under very high penetrations of rooftop solar on the grid.

Grid Security

- APS does not believe that this is a legitimate benefit of rooftop solar. In fact, most solar rooftop systems will not operate when the grid has an outage. In addition, this purported benefit, if any, would only benefit the solar customer and not be shared with other residential customers in general.

PURPORTED BENEFITS OF ROOFTOP SOLAR THAT DO NOT DIRECTLY IMPACT UTILITY COSTS OR RATES

Jobs

- Central solar and rooftop solar would both have a positive, but different, direct impact on local jobs. Under the current net metering program, residential rooftop solar has a higher impact on electric rates compared with central solar and therefore would have a higher negative indirect impact on jobs compared with central solar.

Additional environmental benefits not currently expected to be reflected in utility costs

- Both rooftop solar and central solar would be expected to have similar environmental benefits because they both offset conventional generation.

Health effects

- Both rooftop solar and central solar would provide similar health benefits because they both offset conventional generation.

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Staff 1.35: Would central planning and the targeted deployment of subtransmission level PV, in a manner described by APS, likely produce greater value on a capacity basis than customer-sited solar DG? Wouldn't this allow for APS to deploy solar PV where it has the greatest opportunity to defer distribution and transmission capital investments compared to the current regime of solar DG, where customers, not APS decide when and where to deploy solar PV?

Response: Yes. Targeted deployment of solar PV by APS would produce greater value on a capacity basis than customer-sited solar DG because APS could install larger centrally located single-axis tracking solar systems which have higher capacity factors and higher capacity values than fixed-panel customer-sited solar systems. APS is in a better position to select the type and size of centrally located solar PV projects, and locate them where there is opportunity to defer distribution in order to maximize benefits of solar generation to its customers.

In fact, SEIA acknowledges that the "targeted deployment of wholesale solar DG can produce similar direct value to ratepayers as the value of demand-side solar outlined in the Crossborder study. Targeted deployment of wholesale (or retail) solar DG has the potential to increase the likelihood that solar DG will result in significant transmission and distribution (T&D) savings."[1]

More benefits of centrally located generation are discussed in APS' Response to Staff 1.34.

[1] *See* SEIA Response to Staff's First Set of Data Requests to SEIA, Question 11.

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Staff 1.36: The Net Metering Rules require the installation of bidirectional meters at all net metered facilities. Do these bidirectional meters measure customer demand? If not, what additional metering equipment would be necessary for utilization of rates with demand-based charges? What is the average cost of this additional equipment?

Response: Yes, APS's bidirectional meters measure customer demand. No additional equipment is necessary.

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Staff 1.37: What is the average monthly demand charge for APS' ECT-TOU customers?

Response: The average monthly demand for ECT-2 customers is 7.1 kW, 8.5 kW for summer months and 5.6 kW for winter months, based on load research information. The resulting average monthly billed amount for demand is approximately $ 83.50, $115 for summer months and $52 for winter months (rounded), based on current rates.

However, APS does not believe that this information is representative of solar customers, because the typical ECT-2 customer has a higher monthly demand and kWh usage compared with typical solar customers.

APS believes that the ET-2 customer class information is more representative of customers that may adopt solar, for both kWh and kW information. The average monthly demand for ET-2 customers, prior to adding solar, is 6.2 kW, 7.2 kW for summer months and 5.2 kW for winter months, based on load research information. The resulting average monthly billed amount for demand is approximately $72.50, $97 summer and $48 winter (rounded).

The monthly demand charge expected for solar customers under APS's ECT-2 proposal would also depend on the amount of billing demand that the customer can avoid with the solar generator or other actions. Assuming that the solar customer can reduce their billing demand by 10%, the expected monthly demand charge for a typical solar customer would be approximately $66, $88 for summer months, $44 for winter months (rounded). The charges for specific customers will vary from this average. Therefore, a range of potential values are provided below.

Monthly Billing Demands and Charges for Solar Customers

AVG Monthly Billing kW	AVG Monthly Demand Charge ($)
4.0	$ 47
5.0	$ 59
5.6	$ 66
6.0	$ 70
7.0	$ 82

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Staff 1.38: What would the estimated average monthly demand charge be for new solar customers on the ECT-tou rate?

Response: Please refer to the response to Staff 1.37.

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Staff 1.39: What challenges would arise if the Commission allowed grandfathering to run with the property?

Response: From an impact standpoint, the cost shifting of the grandfathered solar generator would persist longer over time, resulting in a higher overall impact on rates. From a fairness standpoint, it would also extend the benefit of grandfathering beyond the current owner. In other words, the Commission would be asking customers to fund the rate subsidy from the current net metering program for someone purchasing a home with solar years after the new program is established.

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Staff 1.41: Did APS perform any cost-benefit analyses of the proposed net metering solutions? If so, please submit the results of these analyses.

Response: Yes. APS assessed the costs and benefits for the current residential net metering program as well as for the proposed solutions. The analysis focused on the overall impact on APS customers and rates. The results are provided in Attachment APS15252.

The assessment compared the costs of rooftop solar to customers, which are the bill savings or revenue reductions from solar customers, with the benefits, which are the reductions in utility costs resulting from the solar generation. Other costs such as program costs, incentives, and integration costs were not included in the analysis.

The results were calculated for two cases: one using current average costs from the cost of service study in our most recent rate case, and the other using current marginal costs from the SAIC study. In both cases, the solar bill savings were estimated using bill simulations from representative customers that were based on actual billing and load research information.

The solar bill savings estimations were then validated by performing a detailed rebilling simulation for thousands of residential solar customers. This simulation utilized actual monthly billing data for a 12 month period along with actual installed solar generation information for each customer. The actual monthly billing information was compared with a simulated bill that would have occurred if the customer had not installed solar. The results of this assessment validated the results of the bill simulations for representative customers, and in particular the estimated $0.135 per kWh bill savings and the $1,000 cost shift per year.

As shown in column 3 of the Attachment, the current residential net metering program results in an estimated bill savings (excluding taxes) for solar customers of approximately $0.135 per kWh, APS cost savings of $0.031 per kWh, based on current marginal costs, for a net loss or rate impact of $0.104 per kWh. For a typical solar customer this results in a net cost shift to other customers of approximately $1,000 per year, or approximately $18 million per year for the current program participation. Furthermore, as shown, this adverse rate impact is expected to grow by $6 to $10 million per year over the next few years.

APS also performed this assessment using the average cost of service, rather than the marginal cost, for estimating the reduced utility costs from rooftop solar. These results are provided in column 2. As shown, the solar bill savings is $0.135 per kWh, the utility cost savings $0.054, for a net cost shifted to other customers of $0.081 per kWh of solar generation, or $808 per year per solar customer.

APS also performed this assessment for the year 2025 to demonstrate that this cost shifting is expected to persist over time. This assessment was performed using projections of both marginal utility costs and average utility costs. The results shown in columns 4 and 5 demonstrate that the cost shifting from the current residential net metering program is expected to persist in the future.

APS's proposed net metering option, which requires net metering participants to be served under the existing rate schedule ECT-2, significantly reduces the cost shift per kWh to $0.042 and $419 per year using current marginal costs and $0.019 per kWh and $190 per year using current average costs (columns 6 and 7). The proposed program would not reduce the current $18 million annual adverse rate impact from the current program because current customers are proposed to be grandfathered. However, the net metering proposal would significantly reduce, but not eliminate, the expected growth in that liability. The expected future impacts for the proposed net metering option with rate ECT-2 are provided in columns 8 and 9.

APS is also proposing a bill credit option where the entire solar kWh generation would be credited on the customer's monthly bill at a specified rate of $0.0402 per kWh. Because this credit rate is based on the expected cost that APS would incur for purchasing electricity in the bulk commodity markets, with some adjustments specific to rooftop solar, the adverse rate impact or cost shifting from rooftop solar would be eliminated under this option (column 9). Again, to be specific, because of the proposed grandfathering provision, the current $18 million annual rate impact would not be reduced. However, the expected growth in this impact would be eliminated.

Staff 1.41

Rate Impacts of Residential Net Metering - Current and Proposed Programs

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	Current Net Metering Program				Proposed Net Metering Option				Bill Credit Option	
	Currrent Average Cost	Current Marginal Cost	Future Average Cost[3]	Future Marginal Cost	Currrent Average Cost	Currrent Marginal Cost	Future Average Cost	Future Marginal Cost	Current Market Price	Future Market Price
Costs of Net Metering										
Solar Bill Savings ($/kWh)[1]	0.135	0.135	0.173	0.173	0.073	0.073	0.093	0.093	0.0402	NA
Benefits of Net Metering										
APS Cost Savings ($/kWh)[2]	0.054	0.031	0.069	0.082	0.054	0.031	0.069	0.082	0.0402	NA
Net Cost Shift ($/kWh)	0.081	0.104	0.104	0.091	0.019	0.042	0.024	0.011	-	-
Cost Shift $ per Year per Customer										
kWh Netted Against Retail Rate	9,977	9,977	9,977	9,977	9,977	9,977	9,977	9,977	9,977	9,977
times Cost Shift per kWh	0.081	0.104	0.104	0.091	0.019	0.042	0.024	0.011	-	-
Cost Shift	808	1,038	1,038	908	190	419	239	110	-	-
Cost Shift $ per Year - Total										
Current Participation ($)	14,544,000	18,684,000	18,684,000	16,344,000	18,684,000	18,684,000	4,302,000	1,980,000	18,684,000	18,684,000
Annual Growth - 2013 level ($)	4,848,000	6,228,000	6,228,000	5,448,000	1,140,000	2,514,000	1,434,000	660,000	-	-
Annual Growth - Expanded ($)	8,080,000	10,380,000	10,380,000	9,080,000	1,900,000	4,190,000	2,390,000	1,100,000	-	-
					see note 4.	see note 4.	see note 4.	see note 4.		

Notes:

1. This summary only includes the solar bill savings as costs. Other costs such as program costs, incentives and integration costs are not included.
   Bill savings for current program based on typical solar customers under current IB and TOU-E rates, excludes taxes
   Bill savings for proposed net metering option based on customer moving from IB and TOU-E rates to ECT-2 rate
   Bill savings for proposed bill credit option based on proposed credit price
2. AVG cost reflects fuel, variable O&M and 50% generation capacity cost,as reflected in cost of service study
   Current marginal cost from 2013 SAIC report, Table 3-7, 2015 nominal value, expected penetration case
   Future marginal cost from 2013 SAIC report, Table 3-7, 2025 nominal value, expected penetration case
3. Uses expected inflation as a general proxy for increases in revenue requirements over time
4. This is a comparative number, not an actual projection. Based on the same 6,000 to 10,000 new solar customers projected under the curent program.

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AUGUST 1, 2013

Staff 1.42: Please provide your rationale behind the statement that the total costs shifted to non-solar customers could increase by an estimated $6-10 million annually. (Page 9). How is the high end of this range derived?

Response: The estimated growth in the annual cost shifting from residential solar rooftop customers was derived by multiplying the current average cost shift per solar customer per year times the expected growth in the number of solar customers. APS performed this calculation in two ways – one based on the current costs embedded in rates and the other based on current marginal costs. The average or embedded utility cost savings reflect the current cost to serve residential customers from the cost of service study in the most recent rate case. The current marginal costs reflect the projected 2015 savings in avoided fuel cost, avoided generation capacity, line losses, and any other relevant cost impact from rooftop solar, as estimated in the SAIC study.

The annual cost shifting per solar customer is roughly $800 based on embedded costs and $1,000 based on current marginal costs. The $6 million estimate is the $1000 per customer times 6,000 new residential solar customers expected in 2013. The $10 million estimate reflects a high growth scenario based on our current exponential growth trend in the adoption of rooftop solar, under the current net metering program. It is calculated by multiplying the $1,000 times an estimated growth level of 10,000 new solar customers per year, which is a potential scenario in the next few years. Details of this estimate are provided in attachment APS15246. In addition, please refer to the Direct Testimony of Charles Miessner pages 13 through 16 for additional discussion on this question.

Staff 1.42

Savings and Cost Shifting from Residential Rooftop Solar
Based on Current Rates and Costs

Inputs	
1,641	Solar kWh/kW - yr
6.4	Solar kW
10,502	Solar kWh per year
875	Solar kWh per month
95%	Solar kWh netted against load
18,000	Current Residential Solar Customers
6,000	Expected annual growth - 2013
10,000	High growth scenario

	Currrent Average Cost w/ tax $/kWh	Currrent Average Cost w/o tax $/kWh	Currrent Marginal Cost w/o tax $/kWh
Cost Shift $ per kWh			
Bill savings	0.150	0.135	0.135
less APS Cost Savings[1]	0.059	0.054	0.031
Cost Shift	0.091	0.081	0.104
Cost Shift $ per Year per Customer			
kWh Netted Against Retail Rate	9,977	9,977	9,977
times Cost Shift per kWh	0.091	0.081	0.104
Cost Shift	908	808	1,038
Cost Shift $ per Year - Total			
Current Participation ($)	16,344,000	14,544,000	18,684,000
Annual Growth - 2013 level ($)	5,448,000	4,848,000	6,228,000
Annual Growth - Expanded ($)	9,080,000	8,080,000	10,380,000

1. Average cost based on fuel, variable O&M and 50% generation capacity cost from COS study
Marginal cost based on 2013 SAIC report, Table 3-7, 2015 nominal value, expected penetration case

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF NET METERING COST SHIFT SOLUTION
DOCKET NO. E-01345A-13-0248
AUGUST 1, 2013

Staff 1.43: Please provide your rationale behind the statement that the ACC's failure to act now on the instant application may preclude the Commission from grandfathering the use of net metering by customers that currently have solar installed on their homes. (Page 10).

Response: If the issue is delayed, at the current rate of an additional 500 residential solar installations per month, the cost shift grows by $500,000 per month. The continued rapid growth in rooftop solar adoption, along with the increased cost shifting burden and resulting rate impact, may be so high that grandfathering would not be feasible.

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DOCKET NO. E-01345A-13-0248
AUGUST 1, 2013

Staff 1.44: Please provide the rationale with supporting details for the assertion on Page 18 of Mr. Miessner's testimony that "These flaws are so fundamental in nature that APS believes the Cross Border (sic) study does not merit serious consideration."

Response: APS believes that the Crossborder study does not merit serious consideration because the results exceed any reasonable range. Specifically, their claim that rooftop solar provides 22 to 24 cents per kWh of utility cost savings levelized over the next 20 years is extremely unreasonable and unlikely. Compare this range to APS's current average residential rate of 12.6¢/kWh. If Crossborder's conclusions were correct, it would mean that a rooftop solar unit can reduce APS's cost of service by roughly twice the current level of total revenue requirements per kWh – that's twice the cost for all of our fleet of generation plants, all of our transmission lines and equipment, all of our substations, primary lines, secondary lines, transformers, service trucks, tools, maintenance equipment, meters, billing and information systems, buildings, and personnel. This is simply not true.

The Crossborder results are also approximately three times the current cost of a solar purchase power agreement for utility scale solar that could be located around a load center and provide roughly the same or more benefits of rooftop solar. Both of these practical assessments show that the Crossborder results do not merit serious consideration. Please see the Company's responses to Staff Questions 1.4, 1.32, and 1.34.

ARIZONA CORPORATION COMMISSION
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DOCKET NO. E-01345A-13-0248
AUGUST 1, 2013

Staff 1.45: With regard to the LFCR discussed on Page 33 of Mr. Miessner's testimony, please provide details and a calculation of the power plant infrastructure costs and the fixed-budget public policy programs costs that will not be collected under the LFCR adjustor.

Response: The LFCR adjustor currently provides partial recovery of distribution and transmission infrastructure costs that are otherwise unrecovered between rate cases due to the growth in energy efficiency and rooftop solar. However, the LFCR excludes unrecovered generation infrastructure costs and fixed budget public policy program costs such as the system benefits, DSMAC and RES charges. Some of the latter costs are recovered through annual adjustors and therefore would not need to be addressed through the LFCR. Others are not. For your convenience, attached as APS15249 is the Plan of Administration for the LFCR which outlines the overall calculations.

For residential customers, the generation infrastructure costs recovered in rates are approximately 2.8 cents per kWh. This is based on the cost of service study in the most recent rate case using 2010 as the test year. The public policy program costs would include the DSMAC adjustor rate, which is currently 0.27 cents per kWh, the RES adjustor, which is approximately 0.32 cents per kWh average recovery from residential customers, and the system benefits charge in base rates, which is 0.27 cents per kWh (numbers rounded to 0.00 cents).

Lost Fixed Cost Recovery ("LFCR") Plan of Administration

Table of Contents

1. General Description

This document describes the plan of administration for the LFCR mechanism approved for Arizona Public Service Company ("APS" or "Company") by the Arizona Corporation Commission ("ACC") on May 24, 2012 in Decision No. 73183. The LFCR mechanism provides for the recovery of lost fixed costs, as measured by revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the portion of transmission costs included in base rates and a portion of distribution costs, other than what is already recovered by (1) the Basic Service Charge and (2) 50% of demand revenues associated with distribution and the base rate portion of transmission.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules, less the amount of revenue attributable to sales to Opt-Out residential customers.

Current Period – The most recent adjustment year, i.e. rate effective year.

Demand Stability Factor – Fifty percent of distribution and transmission demand-based revenue produced by base rates.

DG Savings – The amount of MWh sales reduced by DG. APS shall use statistical verification, output profile, or meter data for DG systems until December 31, 2014. Beginning January 2015, APS shall only use meter data to calculate DG system savings. Each year, APS will use actual data through September and forecast data for the remainder of the calendar year to calculate the savings. The calculation of DG Savings will consist of the following by class:

1. Current Period: The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.
2. Excluded MWh Production: The reduction of recoverable DG Savings calculated as follows: (1) for residential Opt-Out customers by either, dividing the number of Opt-Out residential customers by the total number of residential customers and multiplying that result by total residential DG Savings or using actual metered production, and (2) for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.

3. True-Up Prior Period: The reconciliation of APS's forecast data of DG sales reductions for the three months in the Prior Period to verified DG sales reductions in the Prior Period.

Distribution Revenue – The amount determined at the conclusion of a rate case by multiplying both residential and general service adjusted test year billing determinants (kW and kWh) by their approved delivery charges. Any demand (kW) based delivery revenue will be reduced by the Demand Stability Factor.

EE Programs – Any program approved in APS's annual implementation plan.

EE Savings – The amount of sales, expressed in MWh, reduced by EE as demonstrated by the Measurement, Evaluation, and Reporting ("MER") conducted for EE programs. EE Savings shall be pro-rated for the number of days that new base rates are in effect during the initial implementation of the LFCR. The calculation of EE Savings will consist of the following by class:

1. Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS's most recent general rate case as a starting point.
2. Current Period: The annual EE related sales reductions (MWh). Each year, APS will use actual MER data through September and forecast data for the remainder of the year to calculate savings.
3. Excluded MWh reduction: The reduction of recoverable EE Savings calculated as follows: (1) for residential Opt-Out customers by, dividing the number of Opt-Out residential customers by the total number of residential customers and multiplying that result by Current Period Savings, and (2) for commercial and industrial customers, by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules.
4. True-Up Prior Period: The reconciliation of APS's forecast data of EE sales reductions for the three months in the Prior Period to verified EE sales reductions in the Prior Period.

Excluded Rate Schedules – The LFCR mechanism shall not apply to large general service customers taking service under rate schedules E-32 L, E-32 L TOU, E-34, E-35 and E-36 XL, or to unmetered General Service customers under E-30 and lighting schedules.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue by the Applicable Company Revenues. This adjustment percentage will be applied to all customer bills, excluding both those that have chosen to Opt-Out and those on Excluded Rate Schedules.

LFCR Balancing Account – An account to track the difference between allowed Lost Fixed Cost Revenue and actual amounts billed by the Company through the LFCR adjustment. The balancing account will be reflected in Schedule 2 of the LFCR Compliance Report and shall be calculated by taking the Total Lost Fixed Cost Revenue from Prior Period less the amount billed through the LFCR for the most recent calendar year at the time of filing.

Lost Fixed Cost Rate – A rate determined at the conclusion of a rate case by taking the sum of allowed Distribution Revenue and base rate Transmission Revenue for each rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE and DG during the period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Opt-Out – The rate schedule choice for residential customers to opt out of the LFCR in the form of an optional BSC. The number of Opt-Out customers will be expressed as thc annual average number of customers "Opting-Out" over the Current Period. The LFCR mechanism shall not be applied to residential customers who choose the Opt-Out provision. This rate will be made available to customers at the time of the first LFCR adjustment.

Prior Period – The 12 months preceding the Current Period.

Recoverable MWh Savings – The sum of EE Savings and DG Savings by rate class.

Total Fixed Revenue – The total of Transmission Revenue and Distribution Revenue by Class.

Transmission Revenue – The amount of revenue determined at the conclusion of a general rate case by multiplying both residential and general service adjusted test year billing determinants (kW and kWh) by the approved base rate transmission charge within their respective rate schedules. Any demand (kW) base rate Transmission Revenue will be reduced by the Demand Stability Factor.

3. LFCR Annual Incremental Cap

The LFCR Adjustment will be subject to an annual 1% year over year cap based on Applicable Company Revenues. If the annual LFCR Adjustment results in a surcharge and the annual incremental increase exceeds 1% of Applicable Company Revenues, any amount in excess of the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

4. Filing and Procedural Deadlines

APS will file the calculated Annual LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by January 15th. The new LFCR Adjustment will not go into effect until approved by the Commission.

5. Compliance Reports

APS will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1: LFCR Annual Adjustment Percentage
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: Distribution and Transmission Revenue Calculation – General Service
- Schedule 6: Distribution and Transmission Revenue Calculation – Residential

Schedules 1 through 6, attached hereto, will be submitted with APS's annual compliance filing.

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Adjustment Percentage
($000)

Line No.	(A) **Annual Percentage Adjustment**	(B) **Reference**	(C) **Total**
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15	$ -
2.	Applicable Company Revenues	Schedule 2, Line 1	-
3.	% Applied to Customer's Bills	(Line 1 / Line 2)	0.0000%

Note: For the Current Period, the full revenue per customer decoupling mechanism that was proposed in APS's June 1, 2011 rate application (including all customers and offering no residential Opt-Out alternative) would have resulted in a total revenue adjustment of $X and average customer bill impact of Y%.

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation
($000)

Line No.	(A) **LFCR Annual Incremental Cap Calculation**	(B) **Reference**		(C) **Totals**
1.	Applicable Company Revenues		$	-
2.	Allowed Cap %			1.00%
3.	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	-
4.	Total Lost Fixed Cost Revenue	Schedule 3, Line 38, Column C	$	-
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C		-
6.	Annual Interest Rate			0.00%
7.	Interest Accrued on Deferred Balance	(Line 5 * Line 6)		-
8.	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	-
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10.	Lost Fixed Cost Revenue - Billed[1]		$	-
11.	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	-
13.	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	-
14.	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.00%
15.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	-

[1]Amount billed to customers for the 12 calendar months of 20XX

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation
($000)

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential				
	Energy Efficency Savings				
1.	Current Period			-	MWh
2.	% of Residential Customers on Opt-Out			0.0%	
3.	Excluded MWh reduction	(Line 1 * Line 2)		-	MWh
4.	Net - Current Period	(Line 1 - Line 3)		-	MWh
5.	Prior Period	Previous Filing, Schedule 3, Line 4, Column C			MWh
6.	Verified - Prior Period			-	MWh
7.	True-Up Prior Period	(Line 6 - Line 5)		-	MWh
8.	Cumulative Verified	(Previous Filing, Schedule 3, Line 8, Column C + Line 6)		-	MWh
9.	Total Recoverable EE Savings	(Line 4 + Line 7 + Line 8)		-	MWh
	Distributed Generation Savings				
10.	Current Period			-	MWh
11.	Excluded MWh Production			-	MWh
12.	Net - Current Period	(Line 10 - Line 11)		-	MWh
13.	Prior Period	Previous Filing, Schedule 3, Line 12, Column C		-	MWh
14.	Verified - Prior Period			-	MWh
15.	True-Up Prior Period	(Line 14 - Line 13)		-	MWh
16.	Total Recoverable DG Savings	(Line 12 + Line 15)		-	MWh
17.	Total Recoverable MWh Savings	(Line 9 + Line 16)		-	MWh
18.	Residential - Lost Fixed Cost Rate	Schedule 4, Line 5, Column C	$	0.031111	$/kWh
19.	Residential - Lost Fixed Cost Revenue	(Line 17 * Line 18)	$	-	
	C&I				
	Energy Efficency Savings				
20.	Current Period			-	MWh
21.	Excluded MWh reduction			-	MWh
22.	Net - Current Period	(Line 20 - Line 21)		-	MWh
23.	Prior Period	Previous Filing, Schedule 3, Line 22, Column C		-	MWh
24.	Verified - Prior Period			-	MWh
25.	True-Up Prior Period	(Line 24 - Line 23)		-	MWh
26.	Cumulative Verified	(Previous Filing, Schedule 3, Line 26, Column C + Line 24)		-	MWh
27.	Total Recoverable EE Savings	(Line 22 + Line 25 + Line 26)		-	MWh
	Distributed Generation Savings				
28.	Current Period			-	MWh
29.	MWh DG Savings from Rate Scedules Excluded from LFCR			-	MWh
30.	Net - Current Period	(Line 28 - Line 29)		-	MWh
31.	Prior Period	Previous Filing, Schedule 3, Line 30, Column C		-	MWh
32.	Verified - Prior Period			-	MWh
33.	True-Up Prior Period	(Line 32 - Line 31)		-	MWh
34.	Total Recoverable DG Savings	(Line 30 + Line 33)		-	MWh
35.	Total Recoverable MWh Savings	(Line 27 + Line 34)		-	MWh
36.	C&I - Lost Fixed Cost Rate	Schedule 4, Line 10, Column C	$	0.023190	$/kWh
37.	C&I - Lost Fixed Cost Revenue	(Line 35 * Line 36)	$	-	
38.	**Total Lost Fixed Cost Revenue**	**(Line 19 + Line 37)**	$	-	

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation
($000)

Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference		(C) Total
	Residential Customers			
1.	Distribution Revenue	Schedule 6, Line 13, Column H	$	326,735
2.	Transmission Revenue	Schedule 6, Line 13, Column I	$	65,572
3.	Total Fixed Revenue	(Line 1 + Line 2)	$	392,307
4.	MWh Billed	Schedule 6, Line 12, Column C / 1,000		12,610,002
5.	Lost Fixed Cost Rate	(Line 3 / Line 4)	$	0.031111
	C & I Customers			
6.	Distribution Revenue	Schedule 5, Line 13, Column H	$	155,931
7.	Transmission Revenue	Schedule 5, Line 13, Column I	$	23,093
8.	Total Fixed Revenue	(Line 6 + Line 7)	$	179,024
9.	MWh Billed	Schedule 5, Line 12, Column C / 1,000		7,719,982
10.	Lost Fixed Cost Rate	(Line 8 / Line 9)	$	0.023190

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 5: Distribution and Transmission Revenue Calculation
General Service

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) C*E*(1-G)	(I) C*F*(1-G)	(J) H+I
Line No.	Rate Schedule	Tariff Component	Adjusted Test Year Billing Determinants	Units	Delivery Charge	Transmission Charge	Demand Stability Factor	Distribution Revenue	Transmission Revenue	Total Revenue
1.	E-32 XS	Summer Secondary								
2.		Delivery (1st 5000 kWh per mo.)	684,456,061	kWh	$ 0.04175	$ 0.00424	0%	$ 28,576,041	$ 2,902,094	$ 31,478,135
3.		Delivery (over 5000 kWh per mo.)	74,299,892	kWh	$ 0.01310	$ 0.00424	0%	$ 973,329	$ 315,032	$ 1,288,361
4.		Summer Primary								
5.		Delivery (1st 5000 kWh per mo.)	208,510	kWh	$ 0.03847	$ 0.00424	0%	$ 8,021	$ 884	$ 8,905
6.		Delivery (over 5000 kWh per mo.)	57,060	kWh	$ 0.00983	$ 0.00424	0%	$ 561	$ 242	$ 803
7.		Winter Secondary								
8.		Delivery (1st 5000 kWh per mo.)	593,445,292	kWh	$ 0.04168	$ 0.00424	0%	$ 24,734,800	$ 2,516,208	$ 27,251,008
9.		Delivery (over 5000 kWh per mo.)	66,031,288	kWh	$ 0.01303	$ 0.00424	0%	$ 860,388	$ 279,973	$ 1,140,361
10.		Winter Primary								
11.		Delivery (1st 5000 kWh per mo.)	289,917	kWh	$ 0.03837	$ 0.00424	0%	$ 11,124	$ 1,229	$ 12,353
12.		Delivery (over 5000 kWh per mo.)	153,071	kWh	$ 0.00974	$ 0.00424	0%	$ 1,491	$ 649	$ 2,140
13.		Sub Total	-	kW				$ -	$ -	$ -
14.			1,418,941,091	kWh				$ 55,165,755	$ 6,016,311	$ 61,182,066
15.	E-32 S	Secondary								
16.		Delivery 1st 100 kW	8,134,000	kW	$ 8.243	$ 1.585	50%	$ 33,483,066	$ 6,438,270	$ 39,921,336
17.		Delivery All Additional kW	655,000	kW	$ 3.629	$ 1.585	50%	$ 1,188,498	$ 519,088	$ 1,707,586
18.		Delivery - All kWh	2,541,774,000	kWh	$ 0.00423	$ -	0%	$ 10,751,704	$ -	$ 10,751,704
19.		Primary								
20.		Delivery 1st 100 kW	15,000	kW	$ 7.531	$ 1.585	50%	$ 56,483	$ 11,888	$ 68,371
21.		Delivery All Additional kW	46,000	kW	$ 2.917	$ 1.585	50%	$ 67,091	$ 36,455	$ 103,546
22.		Delivery - All kWh	10,208,000	kWh	$ 0.00423	$ -	0%	$ 43,180	$ -	$ 43,180
23.		Sub Total	8,850,000	kW				$ 34,795,138	$ 7,005,701	$ 41,800,839
24.			2,551,982,000	kWh				$ 10,794,884	$ -	$ 10,794,884
25.	E-32 M	Secondary								
26.		Delivery 1st 100 kW	4,680,000	kW	$ 8.650	$ 1.585	50%	$ 20,241,000	$ 3,708,900	$ 23,949,900
27.		Delivery All Additional kW	4,562,000	kW	$ 3.800	$ 1.585	50%	$ 8,667,800	$ 3,615,385	$ 12,283,185
28.		Delivery - All kWh	3,243,059,000	kWh	$ 0.00649	$ -	0%	$ 21,047,453	$ -	$ 21,047,453
29.		Primary								
30.		Delivery 1st 100 kW	33,000	kW	$ 7.903	$ 1.585	50%	$ 130,400	$ 26,153	$ 156,553
31.		Delivery All Additional kW	60,000	kW	$ 3.110	$ 1.585	50%	$ 93,300	$ 47,550	$ 140,850
32.		Delivery - All kWh	36,483,000	kWh	$ 0.00649	$ -	0%	$ 236,775	$ -	$ 236,775
33.		Transmission								
34.		Delivery 1st 100 kW	-	kW	$ 5.783	$ 1.585	50%	$ -	$ -	$ -
35.		Delivery All Additional kW	-	kW	$ 0.934	$ 1.585	50%	$ -	$ -	$ -
36.		Delivery - All kWh	-	kWh	$ 0.00649	$ -	0%	$ -	$ -	$ -
37.		Sub Total	9,335,000	kW				$ 29,132,500	$ 7,397,988	$ 36,530,488
38.			3,279,542,000	kWh				$ 21,284,228	$ -	$ 21,284,228
39.	E-32 TOU XS	Summer Secondary								
40.		Delivery On Pk (1st 5000 kWh per mo.)	628,000	kWh	$ 0.05065	$ 0.00424	0%	$ 31,808	$ 2,663	$ 34,471
41.		Delivery - All additional kWh	-	kWh	$ 0.01316	$ 0.00424	0%	$ -	$ -	$ -
42.		Delivery Off Pk (1st 5000 kWh per mo.)	1,553,000	kWh	$ 0.04174	$ 0.00424	0%	$ 64,822	$ 6,585	$ 71,407
43.		Delivery - All additional kWh	85,000	kWh	$ 0.00962	$ 0.00424	0%	$ 818	$ 360	$ 1,178
44.		Summer Primary								
45.		Delivery On Pk (1st 5000 kWh per mo.)	-	kWh	$ 0.04730	$ 0.00424	0%	$ -	$ -	$ -
46.		Delivery - All additional kWh	-	kWh	$ 0.00902	$ 0.00424	0%	$ -	$ -	$ -
47.		Delivery Off Pk (1st 5000 kWh per mo.)	-	kWh	$ 0.03838	$ 0.00424	0%	$ -	$ -	$ -
48.		Delivery - All additional kWh	-	kWh	$ 0.00627	$ 0.00424	0%	$ -	$ -	$ -
49.		Winter Secondary								
50.		Delivery On Pk (1st 5000 kWh per mo.)	647,000	kWh	$ 0.05057	$ 0.00424	0%	$ 32,719	$ 2,743	$ 35,462
51.		Delivery - All additional kWh	3,000	kWh	$ 0.01304	$ 0.00424	0%	$ 39	$ 13	$ 52
52.		Delivery Off Pk (1st 5000 kWh per mo.)	1,604,000	kWh	$ 0.04164	$ 0.00424	0%	$ 66,791	$ 6,801	$ 73,592
53.		Delivery - All additional kWh	89,000	kWh	$ 0.00954	$ 0.00424	0%	$ 849	$ 377	$ 1,226
54.		Winter Primary								
55.		Delivery On Pk (1st 5000 kWh per mo.)	-	kWh	$ 0.04721	$ 0.00424	0%	$ -	$ -	$ -
56.		Delivery - All additional kWh	-	kWh	$ 0.00890	$ 0.00424	0%	$ -	$ -	$ -
57.		Delivery Off Pk (1st 5000 kWh per mo.)	-	kWh	$ 0.03829	$ 0.00424	0%	$ -	$ -	$ -
58.		Delivery - All additional kWh	-	kWh	$ 0.00618	$ 0.00424	0%	$ -	$ -	$ -
59.		Sub Total	-	kW				$ -	$ -	$ -
60.			4,609,000	kWh				$ 197,846	$ 19,542	$ 217,388
61.	E-32 TOU S	Secondary								
62.		On Pk 1st 100 kW	94,000	kW	$ 5.775	$ 1.585	50%	$ 271,425	$ 74,495	$ 345,920
63.		On Pk all add kW	13,000	kW	$ 1.185	$ 1.585	50%	$ 7,703	$ 10,303	$ 18,006
64.		Off Pk 1st 100 kW	100,000	kW	$ 2.842	$ 1.585	50%	$ 142,100	$ 79,250	$ 221,350
65.		Off Pk all add kW	24,000	kW	$ 0.412	$ 1.585	50%	$ 4,944	$ 19,020	$ 23,964
66.		Primary								
67.		On Pk 1st 100 kW	-	kW	$ 5.317	$ 1.585	50%	$ -	$ -	$ -
68.		On Pk all add kW		kW	$ 1.117	$ 1.585	50%	$ -	$ -	$ -
69.		Off Pk 1st 100 kW	1,000	kW	$ 2.267	$ 1.585	50%	$ 1,134	$ 793	$ 1,927
70.		Off Pk all add kW	2,000	kW	$ 0.333	$ 1.585	50%	$ 333	$ 1,585	$ 1,918
71.		Sub Total	234,000	kW				$ 427,639	$ 185,446	$ 613,085
72.			41,567,000	kWh				$ -	$ -	$ -
73.	E-32 TOU M	Secondary								
74.		On Pk 1st 100 kW	84,000	kW	$ 8.318	$ 1.585	50%	$ 349,356	$ 66,570	$ 415,926
75.		On Pk all add kW	72,000	kW	$ 3.165	$ 1.585	50%	$ 113,940	$ 57,060	$ 171,000
76.		Off Pk 1st 100 kW	86,000	kW	$ 3.894	$ 1.585	50%	$ 167,442	$ 68,155	$ 235,597
77.		Off Pk all add kW	89,000	kW	$ 1.165	$ 1.585	50%	$ 51,843	$ 70,533	$ 122,376
		Delivery - All kWh	69,937,000	kWh	$ 0.00910	$	0%	$ 636,427	$ -	$ 636,427
78.		Primary								
79.		On Pk 1st 100 kW		kW	$ 7.803	$ 1.585	50%	$ -	$ -	$ -
80.		On Pk all add kW		kW	$ 3.088	$ 1.585	50%	$ -	$ -	$ -
81.		Off Pk 1st 100 kW		kW	$ 3.248	$ 1.585	50%	$ -	$ -	$ -
82.		Off Pk all add kW		kW	$ 1.076	$ 1.585	50%	$ -	$ -	$ -
		Delivery - All kWh		kWh	$ 0.00910	$	0%	$ -	$ -	$ -
83.		Transmission								
84.		On Pk 1st 100 kW		kW	$ 6.882	$ 1.585	50%	$ -	$ -	$ -
85.		On Pk all add kW		kW	$ 2.771	$ 1.585	50%	$ -	$ -	$ -

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 5: Distribution and Transmission Revenue Calculation
General Service

86.			Off Pk 1st 100 kW	-	kW	$ 2.519	$ 1.585	50%	$ -	$ -	$ -
87.			Off Pk all add kW	-	kW	$ 0.956	$ 1.585	50%	$ -	$ -	$ -
			Delivery - All kWh	-	kWh	$ 0.00910	$ -	0%	$ -	$ -	$ -
88.		Sub Total		331,000	kW				$ 682,581.00	$ 262,318.00	$ 944,899.00
89.				69,937,000	kWh				$ 636,427.00	$ -	$ 636,427.00
90.	E-20										
91.				-	kW	$ -	$ -	50%	$ -	$ -	$ -
92.				36,664,000	kWh	$ -	$ -	0%	$ -	$ -	$ -
93.		Sub Total		-	kW				$ -	$ -	$ -
94.				36,664,000	kWh				$ 871,742	$ 247,348	$ 1,119,090
95.	E-36 M	Summer Secondary									
96.			Delivery (1st 5000 kWh per mo.)	-	kWh	$ 0.04175	$ 0.00424	0%	$ -	$ -	$ -
97.			Delivery (over 5000 kWh per mo.)	-	kWh	$ 0.01310	$ 0.00424	0%	$ -	$ -	$ -
98.		Summer Primary									
99.			Delivery (1st 5000 kWh per mo.)	-	kWh	$ 0.03847	$ 0.00424	0%	$ -	$ -	$ -
100.			Delivery (over 5000 kWh per mo.)	-	kWh	$ 0.00983	$ 0.00424	0%	$ -	$ -	$ -
101.		Winter Secondary									
102.			Delivery (1st 5000 kWh per mo.)	-	kWh	$ 0.04168	$ 0.00424	0%	$ -	$ -	$ -
103.			Delivery (over 5000 kWh per mo.)	-	kWh	$ 0.01303	$ 0.00424	0%	$ -	$ -	$ -
104.		Winter Primary									
105.			Delivery (1st 5000 kWh per mo.)	-	kWh	$ 0.03837	$ 0.00424	0%	$ -	$ -	$ -
106.			Delivery (over 5000 kWh per mo.)	-	kWh	$ 0.00974	$ 0.00424	0%	$ -	$ -	$ -
107.		Secondary									
108.			Delivery 1st 100 kW	-	kW	$ 15.068	$ 1.585	50%	$ -	$ -	$ -
109.			Delivery All Additional kW	-	kW	$ 8.186	$ 1.585	50%	$ -	$ -	$ -
110.			Delivery - All kWh	-	kWh	$ 0.00011	$ -	0%	$ -	$ -	$ -
111.		Primary									
112.			Delivery 1st 100 kW	-	kW	$ 13.010	$ 1.585	50%	$ -	$ -	$ -
113.			Delivery All Additional kW	-	kW	$ 7.128	$ 1.585	50%	$ -	$ -	$ -
114.			Delivery - All kWh	-	kWh	$ 0.00011	$ -	0%	$ -	$ -	$ -
115.		Transmission									
116.			Delivery 1st 100 kW	-	kW	$ 8.203	$ 1.585	50%	$ -	$ -	$ -
117.			Delivery All Additional kW	-	kW	$ 3.024	$ 1.585	50%	$ -	$ -	$ -
118.			Delivery - All kWh	-	kWh	$ 0.00011	$ -	0%	$ -	$ -	$ -
119.		Sub Total		-	kW				$ -	$ -	$ -
120.				-	kWh				$ -	$ -	$ -
121.	E-67										
122.				-	kW	$ -	$ -	50%	$ -	$ -	$ -
123.				3,432,000	kWh	$ -	$ -	0%	$ -	$ -	$ -
124.		Sub Total		-	kW				$ -	$ -	$ -
125.				3,432,000	kWh				$ 98,092	$ 4,671	$ 102,763
126.	E-221										
127.				-	kW	$ -	$ -	50%	$ -	$ -	$ -
128.				291,231,000	kWh	$ -	$ -	0%	$ -	$ -	$ -
129.		Sub Total		-	kW				$ -	$ -	$ -
130.				291,231,000	kWh				$ 1,844,426	$ 1,953,946	$ 3,798,372
131.	E-221 8T										
132.				-	kW	$ -	$ -	50%	$ -	$ -	$ -
133.				22,077,000	kWh	$ -	$ -	0%	$ -	$ -	$ -
134.		Sub Total		-	kW				$ -	$ -	$ -
135.				22,077,000	kWh				$ -	$ -	$ -
136.	GS-Schools M	Secondary									
137.			Delivery 1st 100 kW		kW	$ -	$ -	50%	$ -	$ -	$ -
138.			Delivery All Additional kW		kW	$	$ -	50%	$ -	$ -	$ -
139.			Delivery - All kWh	-	kWh	$	$ -	0%	$ -	$ -	$ -
140.		Primary									
141.			Delivery 1st 100 kW	-	kW	$ -	$ -	50%	$ -	$ -	$ -
142.			Delivery All Additional kW		kW	$	$	50%	$ -	$ -	$ -
143.			Delivery - All kWh	-	kWh	$	$	0%	$ -	$ -	$ -
144.		Transmission									
145.			Delivery 1st 100 kW		kW	$	$ -	50%	$ -	$ -	$ -
146.			Delivery All Additional kW		kW	$	$	50%	$ -	$ -	$ -
147.			Delivery - All kWh	-	kWh	$ -	$ -	0%	$ -	$ -	$ -
148.		Sub Total		-	kW				$ -	$ -	$ -
149.				-	kWh				$ -	$ -	$ -
150.	GS-Schools L	Secondary									
151.			Delivery 1st 100 kW		kW	$	$	50%	$ -	$ -	$ -
152.			Delivery All Additional kW		kW	$	$	50%	$ -	$ -	$ -
153.			Delivery - All kWh		kWh	$	$	0%	$ -	$ -	$ -
154.		Primary									
155.			Delivery 1st 100 kW		kW	$	$ -	50%	$ -	$ -	$ -
156.			Delivery All Additional kW		kW	$	$	50%	$ -	$ -	$ -
157.			Delivery - All kWh		kWh	$	$	0%	$ -	$ -	$ -
158.		Transmission									
159.			Delivery 1st 100 kW		kW	$	$	50%	$ -	$ -	$ -
160.			Delivery All Additional kW		kW	$	$	50%	$ -	$ -	$ -
161.			Delivery - All kWh	-	kWh	$ -	$ -	0%	$ -	$ -	$ -
162.		Sub Total		-	kW				$ -	$ -	$ -
163.				-	kWh				$ -	$ -	$ -
164.	Total kW			18,740,000	kW				$ 65,037,858	$ 14,851,453	$ 79,889,311
165.	Total kWh			7,719,982,091	kWh				$ 90,893,400	$ 8,241,818	$ 99,135,218
166.	Total								$ 155,931,258	$ 23,093,271	$ 179,024,529

Arizona Public Service Company
Lost Fixed Cost Recovery Mechanism
Schedule 6: Distribution and Transmission Revenue Calculation
Residential

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
								C*E*(1-G)	C*F*(1-G)	H+I
Line No.	Rate Schedule	Tariff Component	Adjusted Test Year Billing Determinants	Units	Delivery Charge	Transmission Charge	Demand Stability Factor	Distribution Revenue	Transmission Revenue	Total Revenue
1.	E-12									
2.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
3.			4,026,662,000	kWh	$ 0.02700	$ 0.00520	0%	$ 108,719,874	$ 20,938,642	$ 129,658,516
4.		Sub Total	-	kW				$ -	$ -	$ -
5.			4,026,662,000	kWh				$ 108,719,874	$ 20,938,642	$ 129,658,516
6.	ET-1									
7.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
8.			4,344,033,000	kWh	$ 0.02700	$ 0.00520	0%	$ 117,288,891	$ 22,588,972	$ 139,877,863
9.		Sub Total	-	kW				$ -	$ -	$ -
10.			4,344,033,000	kWh				$ 117,288,891	$ 22,588,972	$ 139,877,863
11.	ET-2									
12.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
13.			1,919,486,000	kWh	$ 0.02700	$ 0.00520	0%	$ 51,826,122	$ 9,981,327	$ 61,807,449
14.		Sub Total	-	kW				$ -	$ -	$ -
15.			1,919,486,000	kWh				$ 51,826,122	$ 9,981,327	$ 61,807,449
16.	ECT-1R									
17.		Summer	2,618,000	kW	$ 3.90000	$ -	50%	$ 5,105,100	$ -	$ 5,105,100
18.			751,315,000	kWh	$ 0.01540	$ 0.00520	0%	$ 11,570,251	$ 3,906,838	$ 15,477,089
19.										
20.		Winter	1,754,000	kW	$ 2.30000	$ -	50%	$ 2,017,100	$ -	$ 2,017,100
21.			467,580,000	kWh	$ 0.01700	$ 0.00520	0%	$ 7,948,860	$ 2,431,416	$ 10,380,276
22.		Sub Total	4,372,000	kW				$ 7,122,200	$ -	$ 7,122,200
23.			1,218,895,000	kWh				$ 19,519,111	$ 6,338,254	$ 25,857,365
24.	ECT-2									
25.		Summer	2,036,000	kW	$ 4.50000	$ -	50%	$ 4,581,000	$ -	$ 4,581,000
26.			690,590,000	kWh	$ 0.01400	$ 0.00520	0%	$ 9,668,260	$ 3,591,068	$ 13,259,328
27.										
28.		Winter	1,216,000	kW	$ 2.40000	$ -	50%	$ 1,459,200	$ -	$ 1,459,200
29.			408,035,000	kWh	$ 0.01590	$ 0.00520	0%	$ 6,487,757	$ 2,121,782	$ 8,609,539
30.		Sub Total	3,252,000	kW				$ 6,040,200	$ -	$ 6,040,200
31.			1,098,625,000	kWh				$ 16,156,017	$ 5,712,850	$ 21,868,867
32.	ET-SP									
33.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
34.			2,301,000	kWh	$ 0.02700	$ 0.00520	0%	$ 62,127	$ 11,965	$ 74,092
35.		Sub Total	-	kW				$ -	$ -	$ -
36.			2,301,000	kWh				$ 62,127	$ 11,965	$ 74,092
37.	ET-EV									
38.			-	kW	$ -	$ -	50%	$ -	$ -	$ -
39.			-	kWh	$ 0.02700	$ 0.00520	0%	$ -	$ -	$ -
40.		Sub Total	-	kW				$ -	$ -	$ -
41.			-	kWh				$ -	$ -	$ -
42.	Total kW		7,624,000	kW				$ 13,162,400	$ -	$ 13,162,400
43.	Total kWh		12,610,002,000	kWh				$ 313,572,142	$ 65,572,010	$ 379,144,152
44.	Total							$ 326,734,542	$ 65,572,010	$ 392,306,552

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION OF ARIZONA PUBLIC SERVICE
COMPANY FOR APPROVAL OF NET METERING COST SHIFT SOLUTION
DOCKET NO. E-01345A-13-0248
AUGUST 1, 2013

Staff 1.48: Please provide copy of all DRs from other parties and responses to those DRs.

Response: **APS will provide all data requests and data request responses in this docket as they become available.**

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF NET METERING COST SHIFT SOLUTION
DOCKET NO. E-01345A-13-0248
AUGUST 1, 2013

Staff 1.49: APS asserts that the reason for proposing the Net Metering Cost Shift Solution under docket No. E-01345A-13-0248 is not related to lost revenues, but rather is a matter of customer fairness. Based on this assertion, if the Commission were to take no action on APS's proposed net metering solution, would APS be satisfied with allowing the financial implications of the proposal to be determined during the next general rate case, assuming that APS's financial requirements are satisfied in that rate case, exclusive of APS's fairness concerns?

Response: **APS's principal concern in this matter is the cost shifting caused by net metered rooftop solar installations, which will result in adverse rate impacts to non-solar customers, rather than current financial implications to APS. Therefore, APS would not recommend a delay in this matter to the next rate case. Such a delay would only increase the magnitude of the cost shift and adverse rate impacts, and thus make it harder and more costly to solve this issue.**