



BEFORE THE ARIZONA CORPORATION

COMMISSIONERS

BOB STUMP - Chairman  
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SUSAN BITTER SMITH

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AZ CORP COMMISSION  
DOCKET CONTROL

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

STAFF'S NOTICE OF FILING DATA  
RESPONSES

On August 21, 2013 Commissioner Susan Bitter-Smith requested that the parties file all data requests and responses in this docket. Arizona Corporation Commission Staff ("Staff") hereby files the data responses it has received to date.

RESPECTFULLY SUBMITTED this 26<sup>th</sup> day of August 2013.

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Charles H. Hains, Attorney  
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Original and thirteen (13) copies  
of the foregoing filed this  
26<sup>th</sup> day of August 2013 with:

Docket Control  
Arizona Corporation Commission  
1200 West Washington Street  
Phoenix, Arizona 85007

Arizona Corporation Commission  
DOCKETED

AUG 26 2013

DOCKETED BY  
nr

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August 20, 2013

Constance Fitzsimmons  
Arizona Corporation Commission  
1200 W. Washington  
Phoenix, AZ 85007

RE: Arizona Public Service Company's Application for  
Approval of Net Metering Cost Shift Solution  
Docket No. E-01345A-13-0248

Attached please find Arizona Public Service Company's Response to Staff's First Set of Data Requests Questions 1.7, 1.10, 1.14, 1.17, 1.20, 1.23, 1.48, and 1.49 in the above-referenced matter. Remaining responses will be provided at a later date.

If you have any questions regarding this information, please contact me at (602)250-2661.

Sincerely,

A handwritten signature in black ink, appearing to read "Jeffrey W. Johnson", is written over a printed name.

Jeffrey W. Johnson

JJ/cd  
Attachment

cc: Richard Lloyd

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 1.7: 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 1.10: 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 1.14: 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 1.17: 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 1.20: 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.

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



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August 23, 2013

Constance Fitzsimmons  
Arizona Corporation Commission  
1200 W. Washington  
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RE: Arizona Public Service Company's Application for  
Approval of Net Metering Cost Shift Solution  
Docket No. E-01345A-13-0248

Attached please find Arizona Public Service Company's Response to Staff's First Set of Data Requests Questions 1.22, 1.36, 1.39, and 1.43 in the above-referenced matter. Remaining responses will be provided at a later date.

If you have any questions regarding this information, please contact me at (602)250-2661.

Sincerely,

A handwritten signature in black ink, appearing to read "Jeffrey W. Johnson", is written over a printed name.

Jeffrey W. Johnson

JJ/cd  
Attachment

cc: Richard Lloyd

ARIZONA CORPORATION COMMISSION  
 STAFF'S FIRST SET OF DATA REQUESTS  
 REGARDING THE APPLICATION OF ARIZONA PUBLIC SERVICE  
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 DOCKET NO. E-01345A-13-0248  
 AUGUST 1, 2013

Staff 1.22: What dollar value do you ascribe to the environmental benefits (i.e. reduced CO<sub>2</sub>, SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> 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:

	<b><u>CO2</u></b> (in \$/Metric Ton)	<b><u>SO2</u></b> (in \$/Ton)
2015	0.00	2.05
2020	15.72	2.43
2025	22.56	2.94

These CO<sub>2</sub> 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<sub>2</sub> would be zero.

SO<sub>2</sub> values are estimates based on market trading activity and are included in avoided energy costs.

Benefits for avoiding NO<sub>x</sub> 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<sub>10</sub>.

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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 1.39: 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 1.43: 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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August 6, 2013

SENT BY ELECTRONIC MAIL

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**RE: Solar Energy Industries Association's Response to Staff's First Set of Data Requests/Docket No.: E-01345A-13-0248**

Dear Mr. Lloyd and Ms. Fitzsimmons:

Please find enclosed the Solar Energy Industries Association's ("SEIA") response to Staff's First Set of Data Requests in the above-referenced matter. As you know, SEIA is yet to intervene in the attached docket and as such, it is happy to provide these responses as a courtesy to the Commission Staff at this time. Since we are still in the early stage of this proceeding, SEIA hereby reserves the right to revisit the positions taken in the attached responses and, if and changes are made, SEIA will update the responses accordingly and provide such changes to Staff.

Should you have any questions or comments, please feel free to contact me directly at 480-505-3937.

Sincerely,

  
Court S. Rich

Enclosure

**SOLAR ENERGY INDUSTRIES ASSOCIATION'S RESPONSE TO  
STAFF'S FIRST SET OF DATA REQUESTS  
DOCKET NO.: E-01345A-13-0248**

AUGUST 6, 2013

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**BENEFITS OF SOLAR**

**RL 1-1:** Please respond to Arizona Public Service Company's ("APS") assertion that Crossborder's estimate of 21.5 to 23.7 cents per kWh (\$2014) of benefits from Solar DG on the APS system is twice the amount of APS' current cost of service? Is it realistic to believe that solar DG will save APS twice the amount of its current cost of service?

**SEIA Response:** First, APS's assertion is based on an apples-to-oranges comparison of 20-year levelized numbers to single-year numbers. As is clearly set forth in Crossborder's study, Crossborder's estimate of 21.5 to 23.7 cents per kWh of benefits from Solar DG is a 20-year levelized number which should not be compared to today's cost of service, which is a single-year value. The values for APS's costs of service which are comparable to Crossborder's solar DG benefits are the 20-year levelized costs of solar DG presented in the Crossborder study. As stated in the study, Crossborder's solar DG benefits are 54% higher than APS's costs on a 20-year levelized basis. This is an apples-to-apples comparison and is not "twice" as high.

Second, APS's cost of service is based on the utility's average costs to supply power across all hours using its existing assets. The benefits of solar DG are based on avoiding the marginal costs to serve the most expensive, marginal unit of energy and to build new infrastructure to provide capacity. Solar DG also provides clean, renewable generation that allows the utility to avoid additional costs to obtain energy supplies that are cleaner than its existing portfolio.<sup>1</sup> In other words, on a per unit basis, solar is more valuable than APS's average cost because it provides:

1. Peaking generation when power is most valuable. The energy costs avoided by solar are higher than APS's average energy costs over all hours.
2. Solar supplies valuable peaking capacity. Solar today provides capacity value at approximately 50% of its nameplate capacity even though it produces at only a 20% capacity factor, so on a per unit basis the capacity value of solar is higher than APS's average capacity costs.
3. Avoided capacity costs reflect expensive new generation and transmission that would be built "but for" the solar capacity, while APS's average costs are based on its depreciated existing assets.
4. Solar costs are fixed up front, and avoid APS's costs to manage the volatility of fossil fuel prices and electric market prices. The Crossborder study did not include APS's typical costs to hedge the volatility in the costs of its natural gas supplies; however, if it had included these actual costs, the benefits of solar DG would have increased by another 0.7 to 1.0 cents per kWh.

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<sup>1</sup> Large-scale and wholesale solar also have this effect, but these resources are not the topic of discussion within the study or the NEM debate. Therefore, this response has not focused on them.

**SOLAR ENERGY INDUSTRIES ASSOCIATION'S RESPONSE TO  
STAFF'S FIRST SET OF DATA REQUESTS  
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**CROSSBORDER ASSUMPTIONS:**

**RL 1-2:** Please provide your rationale for using a 50% capacity value for DG, and for not showing any decline in capacity value as penetration levels increase.

**SEIA Response:** Crossborder's study focuses on the value of solar to be developed in the next several years (2013-2015). Over this period, the penetration of solar is not expected to be so large that there would be a significant decline in capacity value. As a result, Crossborder used essentially the same capacity value for 2015 assumed in the R.W. Beck and SAIC studies and the same capacity value that APS itself has assigned to solar when testifying before the Commission in the recent hearing on its Integrated Resource Plan.

In Crossborder's view, solar DG built in 2015 should be assigned the capacity value that applies in 2015 when that solar unit is installed. It is unfair to attribute to that solar unit built in 2015 the lower forecasted capacity value of a solar unit installed in 2020 or 2025 under an assumption that large amounts of solar are installed after 2015. Similarly, if a new utility generating unit is cost-effective when it enters operations in 2015, it would be unfair to penalize the utility if subsequent changes (a drop in capital costs, technological change, lower demand, or lower energy prices, for example) make that unit not cost-effective in future years.

Further, the assumption that larger penetrations of solar will decrease the capacity value of solar assumes no changes to other aspects of the energy market, including no changes to the hourly profile of end-use customer demand, to future levels of peak demand, or to APS's portfolio of resources. Customer demand response, availability of customer-sited storage, impacts from climate change, and new constraints on fossil generation all could have impacts which increase the future value of solar capacity.

**RL 1-3:** How did you arrive at a REC value of 4.5 cents? How are market costs impacted as market prices increase?

**SEIA Response:** APS's 2012 IRP [Attachment F.1(a)] includes an Enhanced Renewable scenario which features additional purchases of renewables in the 2017-2026 time frame (totaling 4,532 GWh of additional renewable generation by 2026). This compares to the Base case with about 500 GWh per year in additional renewable generation in 2026. Based on the annual revenue requirements for both the Base and Enhanced Renewable scenarios [Attachment F.1(b)], the average cost premium for the incremental renewables in the latter scenario is \$46.55 per MWh from 2017-2026, or \$45.39 per MWh on a 10-year levelized basis. See attached workpapers.

SEIA interprets the second question to be "How are REC market costs impacted as energy market prices increase?" REC market values will decrease if energy market prices increase relative to the costs of renewable generation; REC market values will increase if the costs of renewable generation rise relative to energy market prices.

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**RL 1-4:** When is the appropriate time to begin counting capacity savings from distributed generation?

**SEIA Response:** Capacity savings from distributed generation should be counted immediately. Table 2 the 2012 IRP shows that APS expects continued growth in energy efficiency and demand response programs and in distributed solar resources between 2012 and 2017. These new demand-side resources contribute 1,150 MW to meeting APS's expected peak demands in 2017, and thus contribute to deferring any resource need until 2017. Solar DG should be assigned its proportional share (about 13%) of these capacity savings from demand-side resources. In addition, distributed generation also hedges against events that could accelerate the 2017 need, such as faster-than-expected increases in demand or from the unexpected loss of resources.

**RL 1-5:** What if solar does not defer as much generation as previously thought? How will ratepayers be impacted?

**SEIA Response:** SEIA assumes that "generation" means "generation capacity." If solar does not defer as much generation capacity as it was assumed to do in some prior analysis, then solar's value for ratepayers would be lower, all else being the same. However, if the value of capacity is higher than in the prior analysis, solar's value for ratepayers could increase or remain the same, even if solar does not defer as much capacity as was assumed in the initial analysis.

**RL 1-6:** Why use a Combustion Turbine as the marginal unit for energy?

**SEIA Response:** Information provided by APS on its typical loading order, such as Figure 5-3 of the Beck Study, show that solar DG systems on the APS system will displace combustion turbine (CT) generation during the four peak summer months. As shown in Figure 2 of the Crossborder study, the heat rate of a new CT (9,400 Btu/kWh) is the most likely scenario for the market value of the on-peak generation from a solar DG resource during APS's summer season months (June - September) unless APS opts to build additional renewables. This conclusion was based on Palo Verde forward market heat rates for these months. 9,400 Btu per kWh is an average: in some summer on-peak hours, less expensive CCGT power (7,000 - 8,000 Btu/kWh) will be displaced; in others, more expensive generation from older CTs (10,000 - 12,000 Btu/kWh) will be avoided.

**RL 1-7:** Is Crossborder obtaining a much higher levelized rate for generation than what is included in APS's IRP plan? If so, why?

**SEIA Response:** No. Crossborder's study does not include levelized costs for generation such as are included in the APS IRP. The Crossborder study is a Ratepayer Impact Measure (RIM) test. RIM tests do not include levelized costs for generation - the cost side of a RIM test is principally lost utility revenues. The benefit side is principally the utility's avoided fuel, line loss, infrastructure capacity, and environmental costs. Other types of tests (Total Resource Cost

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and Participant) do include the costs of the generation source, but those are not included in the Crossborder study.

**RL 1-8:** Please provide details of your rationale for the statement "...the costs for APS ratepayers will be lower if it is customers, instead of APS, who install renewable [DG] generation."

**SEIA Response:** APS must comply with Arizona's current and future Renewable Energy Standard (RES) requirements. Crossborder understands that solar DG installed by customers with their private capital contributes to meeting those requirements and, assuming that utility incentives are not offered going forward, none of these costs are borne by ratepayers.

**RL 1-9:** How is the customer's capital investment valued in the Crossborder model?

**SEIA Response:** The Crossborder study values the DG customer's capital investment in solar at the capital investment-related costs for the capacity which APS does not have to build or buy as a result of the DG customer's contribution to the infrastructure which serves APS customers.

**RL 1-10:** How are O&M costs of customer-sited DG valued in the Crossborder model?

**SEIA Response:** The Crossborder study values the O&M costs of customer-sited DG based on the fixed and variable O&M costs which APS does not incur as a result of the DG customer's contribution to the infrastructure which serves APS customers. Variable O&M costs are included in the avoided cost of energy; fixed O&M cost are included in the avoided cost of capacity.

**RL 1-11:** Is targeted deployment of wholesale DG of more value than rooftop solar?

**SEIA Response:** SEIA supports all segments of the solar market, including large-scale, wholesale and retail, behind-the-meter, and solar DG. Each brings significant, yet potentially different benefits. 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.

That said, rooftop (retail) solar DG also provides the opportunity for customers to install and/or own solar themselves using their own private capital or financing opportunities available to them. Policymakers thus should also consider:

- Retail solar brings a new source of private capital (from the customers themselves) into the market.
- There is a significant customer demand for the choice to serve some or all of a customer's electricity demand using renewable power generated on their premises.
- Customers want the option to contribute a clean source of generation to the APS system, even if it requires them to make a long-term financial commitment.

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- Competition and customer choice in supplying electricity at the point of use will provide long term benefits for energy consumers.

**RL 1-12:** How do you address APS's criticism regarding the threshold reasonableness check?

**SEIA Response:** The first portion of the APS criticism regarding the "threshold reasonableness check" is the question staff asks in Question RL 1-1, so please see the response to that question. The second portion of this criticism argues that it would be less expensive for APS to purchase wholesale solar. SEIA responds to this argument in its response to Question RL 1-11 above.

**RL 1-13:** The Crossborder study utilizes the Ratepayer Impact Measure ("RIM") test to calculate cost / benefit valuations. Please perform an analysis utilizing the five (5) traditional utility cost-benefit tests (i.e., Total Resource Cost, Ratepayer Impact Method, Societal Cost, Utility Cost, and Participant Cost) and present the results in a table comparing the five methods. Clearly explain your assumptions for each test.

**SEIA Response:** Objection. This request is unduly burdensome. SEIA and Crossborder utilized the RIM Test methodology because it was the best situated to provide the Commission with the information on ratepayer impacts which it needs to make this decision. The other tests requested are not as stringent as the RIM Test (which is often called the "no losers" test), do not measure ratepayer impacts, and will not provide as meaningful information for the Commission's evaluation. In order to run these calculations SEIA would need to commission entirely new studies costing it tens of thousands of dollars. SEIA is happy to work with Staff to help it develop the information needed to perform any of these other tests on its own; however, it is not in a position to commission these additional studies at this time.

**RL 1-14:** If electric system costs are collected through a utility's energy charge, how should the utility collect those fixed costs when it sells less energy because of a Commission mandate?

**SEIA Response:** If, as the result of a Commission mandate, a utility sells less energy than expected to customers who pay rates that collect costs through energy charges, the utility can continue to have the opportunity to recover its full cost of service through revenue decoupling mechanisms such as the Lost Fixed Cost Recovery (LFCR) mechanism adopted with APS's support in its most recent rate case. As in the case of APS, the LFCR mechanism can be targeted at the sales lost as the result of Commission-mandated demand-side programs. Further, in subsequent rate proceedings, the utility's cost of service can be re-set based on the new level of expected sales, which may be somewhat lower than it would have been absent the Commission-mandated demand-side programs.

For example, it is well known that, as the result of a strong focus on demand-side programs, per capita electric use in California has not changed for the last thirty years, while per capita usage in the rest of the U.S. has increased by 50%. The California utilities have also had full revenue decoupling over this period. This focus on using demand-side programs to restrain

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the state's growth in energy use has not adversely impacted the financial health of the California utilities.

Finally, SEIA supports a detailed examination of APS' rate design and cost recovery mechanisms in its next general rate case to address this and other APS rate design issues. In a general rate case the Commission will have the opportunity to design rates and cost recovery mechanisms that address this issue. For example, in its recently concluded rate case APS asked for revenue decoupling and received the Lost Fixed Cost Recovery Mechanism as a way to deal with this issue. Despite the barely-year-old adoption of the LFCR, APS is now seeking to alter the results of the last rate case with its NEM proposals. SEIA believes this reworking of a policy adopted in a rate case should be addressed in a rate case.

**SAIC ASSUMPTIONS:**

**COSTS OF SOLAR DG**

**RL 1-15:** 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.

**SEIA Response:** There is no question posed. The statement accurately summarizes Crossborder's estimates of the costs of residential and commercial DG on the APS system.

**RL 1-16:** 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]

**SEIA Response:** The future mix of DG customers will depend on ACC policies with respect to net metering, solar DG incentives, and retail rate design. Absent information about these policies, the current DG mix appears to be a reasonable assumption at this time.

**RL 1-17:** Since APS has limited its proposed net metering solution to residential DG, what is the applicable benefit to cost comparison, 21.5 to 24.7 cents to 13.7 cents per kWh, or 21.5 to 24.7 cents to 19.9 to 20.5 cents per kWh?

**SEIA Response:** The first comparison is the applicable benefit to cost comparison if net metering is viewed as a single program that should be available to all customers. The second comparison might be appropriate if net metering were a program focused on residential customers alone (which it is not). It is SEIA's view that net metering should be available to all APS customers, and thus views the first comparison as the appropriate one. SEIA notes that both comparisons indicate that net metering is cost-effective.

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**RL 1-18:** 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, should APS make adjustments such that residential DG produces comparable net benefits to commercial DG?

**SEIA Response:** The numbers are accurate, but, no, SEIA does not agree that residential DG should produce comparable net benefits to commercial DG. The Crossborder study indicates that net metering produces net benefits when the costs of net metering for residential and commercial customers are considered either collectively for both types of customers or individually for each type. On this basis, net metering should be continued in its current form for all APS customers.

The large net benefits for commercial DG indicate, if anything, that commercial solar customers are subsidizing non-participating ratepayers. If any adjustment were to be made based on these results, the adjustment should result in a closer balance of benefits and costs, so that any subsidy to or from solar customers is minimized. From this perspective, APS should consider adopting commercial rates for solar customers with reduced demand charges, to bring the benefits and costs of net metering for commercial customers into closer balance. San Diego Gas & Electric and Southern California Edison have adopted such commercial rates with reduced demand charges and higher TOU energy rates for solar customers (SDG&E Schedule DG-R and SCE's Option R rates).

**RL 1-19:** Does Crossborder dispute the cost estimates APS has produced for residential solar DG?

**SEIA Response:** No. As stated in Section 3 of the Crossborder study, Crossborder's cost estimates for residential solar DG are based on APS's responses to prior ACC staff data requests.

## Incremental Cost of APS Renewables

Year	RE + DE (GWh)			Total Rev Req (MM \$)		
	Base Case	ER Case	Delta	Base Case	ER Case	Delta
2014	3,057	3,057	-	\$ 2,412.2	\$ 2,412.2	\$ -
2015	3,487	3,487	-	\$ 2,509.4	\$ 2,509.4	\$ -
2016	3,586	3,586	-	\$ 2,664.2	\$ 2,664.2	\$ -
2017	3,662	4,220	558	\$ 2,841.5	\$ 2,855.0	\$ 13.5
2018	3,718	4,959	1,241	\$ 2,953.1	\$ 3,015.4	\$ 62.3
2019	4,016	5,806	1,790	\$ 3,086.0	\$ 3,178.7	\$ 92.7
2020	4,102	6,373	2,271	\$ 3,227.0	\$ 3,326.9	\$ 99.9
2021	4,859	7,393	2,534	\$ 3,431.7	\$ 3,543.6	\$ 111.9
2022	5,281	8,302	3,021	\$ 3,681.2	\$ 3,799.3	\$ 118.1
2023	5,638	8,938	3,300	\$ 3,963.1	\$ 4,109.6	\$ 146.5
2024	6,025	10,007	3,982	\$ 4,114.7	\$ 4,339.9	\$ 225.2
2025	6,389	10,920	4,531	\$ 4,340.8	\$ 4,617.9	\$ 277.1
2026	6,711	11,243	4,532	\$ 4,667.6	\$ 4,894.0	\$ 226.4
2027	6,785	11,317	4,532	\$ 4,969.0	\$ 5,236.8	\$ 267.8