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The Benefits and Costs of Solar Distributed Generation for Arizona Public Service

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This report provides a new cost-benefit analysis of the impacts of solar distributed generation (DG) on ratepayers in the service territory of Arizona Public Service (APS). On January 23, 2013, the Arizona Corporation Commission ordered APS to conduct a multi-session technical conference to evaluate the costs and benefits of renewable DG and net energy metering (NEM), as part of the ACC's consideration of the APS Renewable Energy Standard (RES) 2013 Implementation Plan. This report is intended to contribute to the technical conferences and the ACC's future deliberations on the APS 2013 RES Plan, and to provide a different perspective than the studies on the value of solar DG that APS commissioned in 2009 from R.W. Beck (the "Beck Study") and in 2013 from SAIC (the "SAIC Study"), which recently acquired R.W. Beck.

The scope of this report is limited to assessing how demand-side solar will impact APS's ratepayers. In the context of the cost / benefit evaluations of demand-side programs, this analysis is a ratepayer impact measure (RIM) test. It is <u>not</u> a total resource cost (TRC) test that would look more broadly at whether distributed solar resources provide net benefits to Arizona. Generally, policymakers should look at a variety of cost-benefit tests, including the broad TRC test, in evaluating whether to initiate, continue, or expand a demand-side program.

In assessing the benefits and costs of solar DG from a ratepayer perspective, it is important to use a time frame that corresponds to the useful life of a solar DG system, which is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side. When a utility assesses the merits of adding a new power plant, or a new energy efficiency (EE) program, the company will look at the costs to build and operate the plant or the program over their useful lives, compared to the costs avoided by not operating or building other resource options. A central problem with the Beck and SAIC Studies is that they assess the benefits of solar DG only in a single-year "snapshot," without considering the long-term benefits of the solar resource over its full expected life.

In addition, solar DG provides significant benefits as a resource that can be scaled easily, from a system serving a single home to utility-scale plants, and that can be installed with shorter lead times and on a wider variety of sites compared to large-scale fossil generation resources. As APS itself recognizes in its 2012 IRP, DG combines with other small-scale, short-lead-time, demand-side resources such as EE and demand response (DR) programs to reduce APS's need for supply-side generation, both in the near- and long-terms. The Beck and SAIC Studies do not recognize these benefits of solar DG resources; instead, they first construct "blocks" of solar DG of different sizes, corresponding to different scenarios for solar DG penetration, and then analyze each block as though it were a conventional large-scale power plant. As a result, these studies calculate few capacity-related benefits from solar DG except in the higher penetration scenarios that are years in the future. In reality, solar DG and APS's other demand-side programs combine to continuously avoid the need for supply-side resources, and all of these resources should be assigned capacity value commensurate with this role and on a comparable basis.

This report relies on data from APS's 2012 Integrated Resource Plan (2012 IRP), supplemented with data from the Beck Study and with data presented in the series of technical workshops that APS held in March and April 2013. Our intent in using this data is to minimize debates over the input assumptions. We also have used a limited amount of current data from the regional gas and electric markets in which APS operates. Our approach to valuing solar DG makes two key changes to the Beck and SAIC studies: first, our analysis is performed over 20 years, instead of just for single years; and, second, we evaluate the benefits of solar DG based on the change in APS's costs per unit of solar DG installed, without requiring solar DG to be installed in the same "lumpy" increments as large-scale conventional generation. We also draw upon relevant analyses that are standard practice in other states, including the avoided cost "calculator" for demand-side programs adopted by the California Public Utilities Commission (CPUC), as well as new studies such as the value-of-solar analysis that Clean Power Research (CPR) used in developing the solar tariff for Austin Energy.

The costs of solar DG for APS ratepayers are principally the lost revenues from solar DG customers who use their on-site solar generation to serve their own loads and who export excess output back into the grid, thus running the meter backward using net energy metering (NEM). For the costs of solar DG, we rely on data that APS reports on the 20-year levelized rate credits that both residential and business customers who install solar DG will realize from the output of their net-metered systems. Finally, on the cost side we also include APS's remaining DG incentives and the utility's calculated costs to integrate intermittent solar generation into the grid.

Our work concludes that the benefits of DG on the APS system exceed the cost, such that new DG resources will not impose a burden on APS's ratepayers. The following table summarizes our results. The benefits exceed the costs by more than 50%, with a benefit / cost ratio of 1.54. The benefits also exceed the costs in both the residential and commercial markets considered individually. Based on SAIC's projection of 431,000 MWh of incremental solar DG in 2015, these benefits amount to $34 million per year for APS's ratepayers.

Table 1: *Benefits and Costs of Solar DG on the APS System*

Benefits	*20-year levelized cents per kWh (2014 $)*
Energy	6.4 to 7.5
Generation capacity	6.7 to 7.6
Ancillary services & Capacity reserves	1.5
Transmission	2.1 to 2.3
Distribution	0.2
Environmental	0.1
Avoided Renewables	4.5
Total Benefits	**21.5 to 23.7**
Costs	*20-year levelized cents per kWh (2014 $)*
Lost retail rate revenues	13.7
DG incentives	0 to 1.6
Integration costs	0.2
Total Costs	**13.9 to 15.5**

1. Methodology

Solar DG is a long-term resource for the APS system. New solar DG systems will provide benefits for the APS service territory for the next 20 to 30 years. Our principal concern with the SAIC and Beck studies is that they assess the benefits of solar DG only using single year, "snapshot" assessments.[1] Data from APS to perform full 20-year assessments is available from the utility's 2012 IRP, from market data, and from information in the Beck / SAIC Studies. Thus, our analysis develops 20-year levelized benefits and costs for solar DG on the APS system.

Another significant methodological issue is the question of "lumpiness." The Beck and SAIC Studies first aggregate solar DG resources into a "blocks" of resources of different sizes (corresponding to low, medium, or high penetrations), and then treat each block as though it were a conventional large-scale power plant. As a result, these studies show relatively low or zero capacity-related benefits from solar except in the higher penetration scenarios, in which there is enough DG capacity to displace a full combustion turbine (CT) and a 500 kV transmission line. This approach does not recognize several of the most important (and beneficial) characteristics of DG – the shorter lead times and smaller, scalable increments in which DG is deployed, compared to large-scale generation resources. In this respect, DG should be treated like energy efficiency (EE) and demand response (DR), which also are small-scale, short-lead-time resources. The DG included in APS's 2012 IRP combines with EE and DR to meet APS's resource needs in the near term and will help to defer the need for larger-scale resources in the long-run. The 2012 IRP finds that APS does not need new large-scale, fossil resources until 2017. However, the 2012 IRP also shows continued growth in both energy efficiency and demand response programs and in distributed solar resources between 2012 and 2017, such that new demand-side resources will contribute 1,150 MW to meeting APS's peak demands in 2017.[2] As a result, solar DG, along with energy efficiency and demand response, contributes to deferring any resource need until 2017, and solar DG installed before 2017 has greater value than just avoiding short-term energy costs.

We have included a number of additional benefits of DG that the Beck / SAIC studies did not consider, including the following:

- **Avoided ancillary service costs.** Solar DG reduces loads on the APS system. Western Electricity Coordinating Council (WECC) reliability standards require control area operators to maintain operating reserves (spinning and non-spinning) equal to 7% of the load served by thermal generation. As a result, APS can avoid the ancillary service costs associated with the load reduction from solar DG. At the same time, APS may incur additional costs to integrate intermittent solar generation into its system, and we have accounted for these added costs on the cost side of our analysis (see Section 3 below).

- **Capacity reserve costs.** When solar DG reduces peak demands on the APS system, it avoids not only generating capacity but also the associated 15% reserve margin.

1 The original Beck study looked at solar DG benefits in 2010, 2015, and 2025. The new SAIC study examined solar DG benefits in 2015, 2020, and 2025.
2 2012 IRP, at pages 6 (Table 2) and 20.

- **Avoided renewables costs.** Solar DG contributes to APS's compliance with Arizona's current Renewable Energy Standard (RES) requirements, as well as to future increases in those requirements. If customers did not invest in solar DG, APS would have to make such investments. To the extent that renewable capacity is more expensive than fossil capacity, the costs for APS ratepayers will be lower if it is customers, instead of APS, who install renewable generation. Data is available from the APS 2012 IRP to quantify this benefit. We also assume that this benefit encompasses a number of difficult-to-quantify benefits of renewable generation, including:
  - **Price mitigation benefits.** Solar DG reduces the demand for electricity (and for the gas used to produce the marginal kWh of power). These reductions have the broad benefit of lowering prices across the gas and electric markets in which APS operates.
  - **Grid security.** Renewable DG resources are installed as many small, distributed systems and thus are highly unlikely to fail at the same time. They are also located at the point of end use, and thus reduce the risk of outages due to transmission or distribution system failures. This reduces the economic impacts of power outages.
  - **Economic development.** Renewable DG results in more local job creation than fossil generation, enhancing tax revenues.

- **Environmental benefits (CO_2, SO_2, NO_x, PM_{10}, and water).** The 2012 IRP also includes the data needed to quantify certain of the environmental benefits of solar DG, in terms of reduced emissions of criteria air pollutants and lower use of scarce water resources.

For the Beck and SAIC Studies, APS used the PROMOD production cost model to calculate the avoided energy costs of DG. APS has declined to provide any of the details of these production cost results, citing confidentiality concerns with releasing information that might compromise APS's position in short-term energy markets. 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. Instead of such short-term modeling, we have calculated APS's long-run avoided energy costs using natural gas forward market data, and the heat rates, variable O&M costs, and other operating parameters for the long-term fossil resources that solar DG will avoid. Other similar studies have taken a comparable approach to calculating long-term avoided energy costs.[3]

On the cost side, we include the revenues which APS loses from customers serving their own load with DG, the costs of utility incentives (if any) paid to DG customers, and the estimate of solar integration costs which APS determined in a recent study.

The following sections discuss each of the benefits and costs of solar DG on the APS system. Solar DG is a long-term resource for the APS system with an expected useful life of at

[3] This is generally the approach taken in the avoided cost calculator that Energy and Environmental Economics (E3) has developed, and the CPUC has approved, for cost-effectiveness analyses of demand-side programs in California. See http://www.ethree.com/public_projects/cpuc5.php. The DG version of the model is titled "DERAvoidedCostModel_v3.9_2011 v4d.xlsm."

least 20 years. Accordingly, we calculate the benefits and costs of DG over a 20-year period in order to capture fully the value of these long-term resources, and we express the results as 20-year levelized costs using a 7.21% per year discount rate.[4]

2. Benefits of Solar DG

a. Energy

APS's 2012 resource plan makes very clear that the utility's marginal sources of generation are principally natural gas-fired resources. In addition, APS expects renewable generation to compete with, and potentially to displace, a portion of these future gas-fired resources:

> *APS foresees the ability to treat natural gas and renewable energy resources as competing levers during this time period, and resource decisions can be modified from the current plan based on the relative tradeoffs between those fuel sources throughout the intermediate-term stage. For example, APS plans to add over 3,700 MW of natural gas generation capacity and 749 MW of renewable coincident-peak capacity during this stage. In the event that solar, wind, geothermal, or other renewable resources change in value and become a more viable and cost-effective option than natural gas, future resource plans may reflect a balance more commensurate to the Enhanced Renewable Portfolio.*[5]

In the future, to the extent that APS's customers invest in demand-side resources, including on-site solar DG, the resources displaced will be new gas-fired generation.

Accordingly, APS's future avoided energy costs are the energy costs of APS's long-term gas-fired generation resources. To estimate these avoided costs, we first develop a long-term forecast of APS's burnertip cost of gas at its power plants. This forecast uses current (April 1, 2013) forward gas price data from the NYMEX Henry Hub market, the basis differential from the Henry Hub to the Permian basin, plus variable delivery costs over the El Paso Natural Gas (EPNG) system to APS's plants in Arizona. **Figure 1** compares this projection to APS's 2012 IRP cost of gas forecast[6] and to the APS gas cost forecast for 2015, 2020, and 2025 (based on the December 31, 2012 forward market) which SAIC has used. Our gas cost forecast is very similar to the SAIC forecast.

Because our forecast is based on forward market natural gas prices, it represents a cost of gas that APS could fix for the next 20 years. This captures the fuel price hedging benefit of renewable DG, which has no fuel costs and thus avoids the volatility associated with generation sources whose cost depends principally on fossil fuel prices.7

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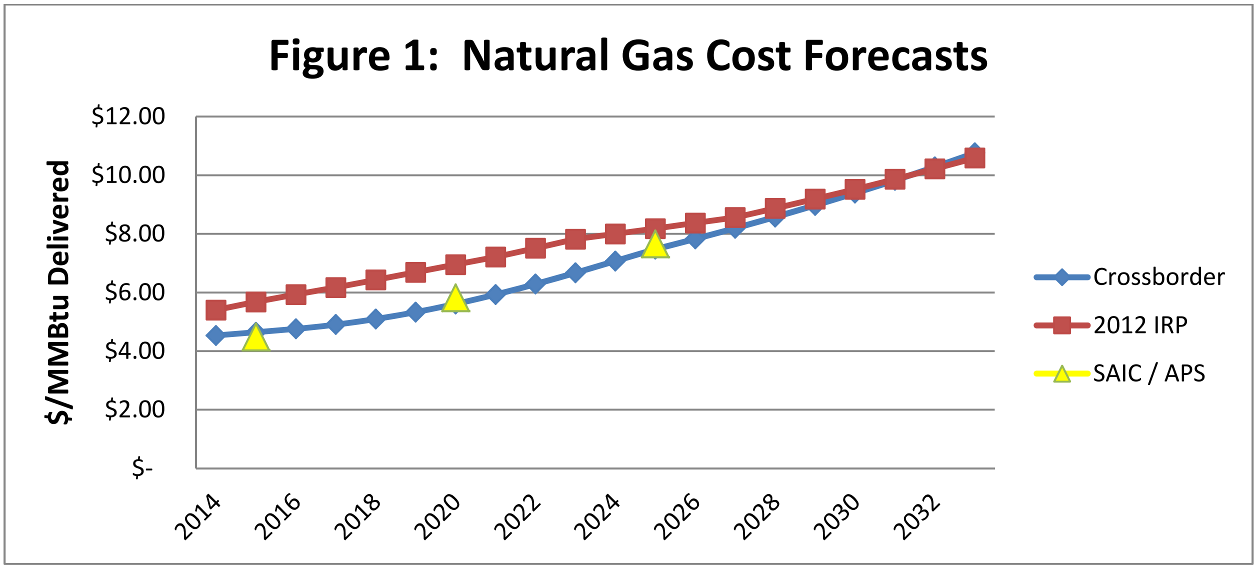
4 The discount rate in the Beck Study was 7.86% (page N-4); the 2012 IRP assumed 7.95% (page 145), and SAIC used the current APS weighted average cost of capital of 7.21% (SAIC April 11, at 77).

5 2012 IRP, at 64.

6 2012 IRP, at Figure 14.

7 In its responses to Vote Solar's Data Requests 1.9 and 2.2, APS provided its costs over the past ten years to hedge the volatility of its natural gas costs. These costs have averaged about $50 million per year, or



Figures 5-3 and 5-5 of the Beck Study show that solar DG systems on the APS system typically displace combustion turbine (CT) generation during the four peak summer months (June-September) and combined-cycle (CCGT) generation in other months. We assume that solar DG avoids generation from new, efficient, state-of-the-art gas plants, with heat rates of 9,400 Btu/kWh for CTs and 7,300 Btu/kWh for CCGTs, plus the corresponding variable O&M costs for such generation.[8] We use our gas price forecast as the fuel costs for these avoided resources. We note that the resulting avoided energy costs in the near term (2014-2015) are close to current forward market prices for the Palo Verde trading hub, as shown in Figures 2 and 3. We also include APS's 2012 IRP forecast of greenhouse gas (GHG) allowance costs ($15 per metric ton, starting in 2019) as an adder to the gas price forecast,[9] using the standard natural gas CO_2 emission rate (117 lbs/MMBtu). Finally, we assume that APS will avoid marginal line losses of 12.1%, based on the detailed analysis of the loss impacts of solar DG that is in the Beck Study.[10] With these inputs, our Base Case forecast of APS's avoided energy costs for solar DG is a 20-year levelized value of 7.1 cents per kWh, in 2014 dollars.

In addition, we have modeled two sensitivity scenarios for APS's avoided energy costs for 2019 and subsequent years. The first is a High Case which assumes APS's High projection of GHG costs from the 2012 IRP. The second sensitivity is a Low Case with zero GHG costs for the next twenty years, which is the Low GHG scenario from the 2012 IRP.

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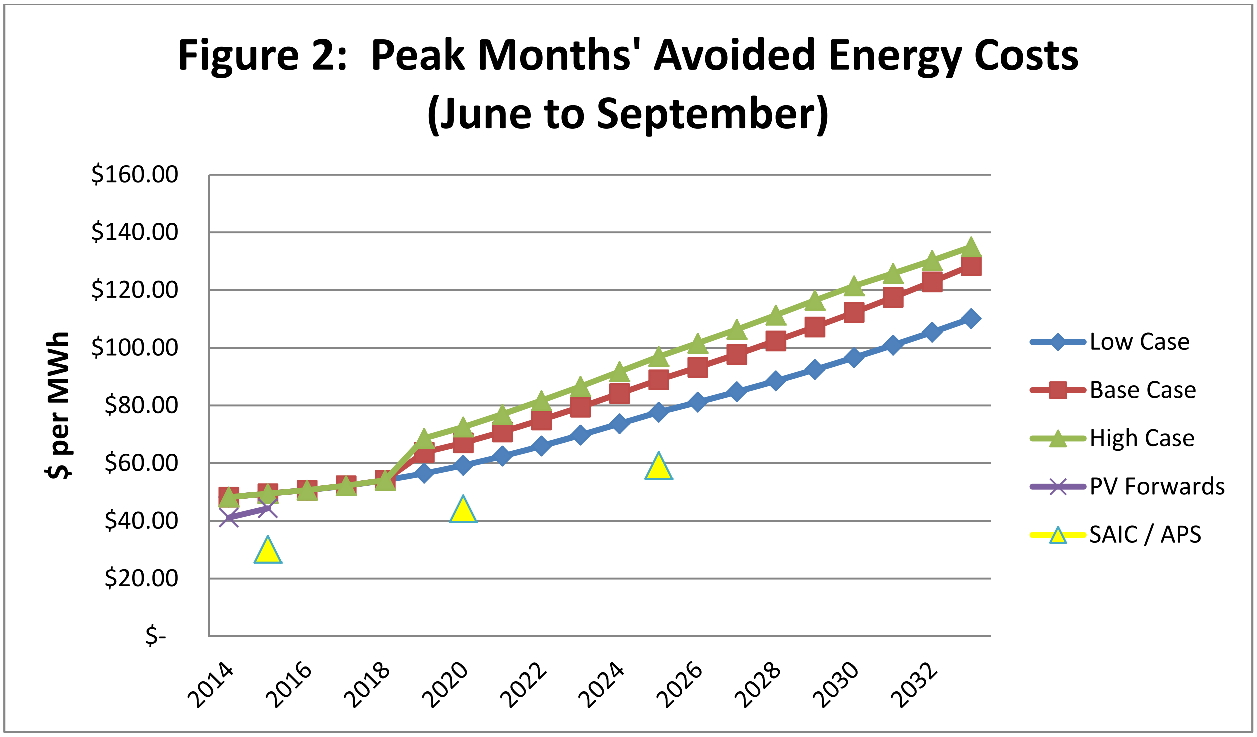
about $1.00 per MMBtu. We did not add these costs to the gas cost forecast for APS, although they appear to be a real, long-term cost of APS's gas procurement strategy.

8 The range of heat rates and variable O&M costs for possible new CTs and CCGTs are shown in the 2012 IRP, at Attachment D.3.

9 2012 IRP, at Figure 15.

10 Beck, at Table 4-3. The SAIC Study appears to use system average line losses on 7% (SAIC April 11, at 59). This does not reflect the fact that solar DG output is produced when system loads, and losses, are higher. It also does not consider that marginal line losses are higher than average losses. The Beck Study includes a full discussion and analysis of the loss issue, at pages 4-4 to 4-8.

Figure 2 shows our Low, Base, and High avoided energy cost forecasts for the peak months of June – September; **Figure 3** presents the results for the off-peak months of October through March. **Table 2** summarizes the resulting 20-year levelized avoided energy costs for solar DG in APS's service territory, including avoided line losses.



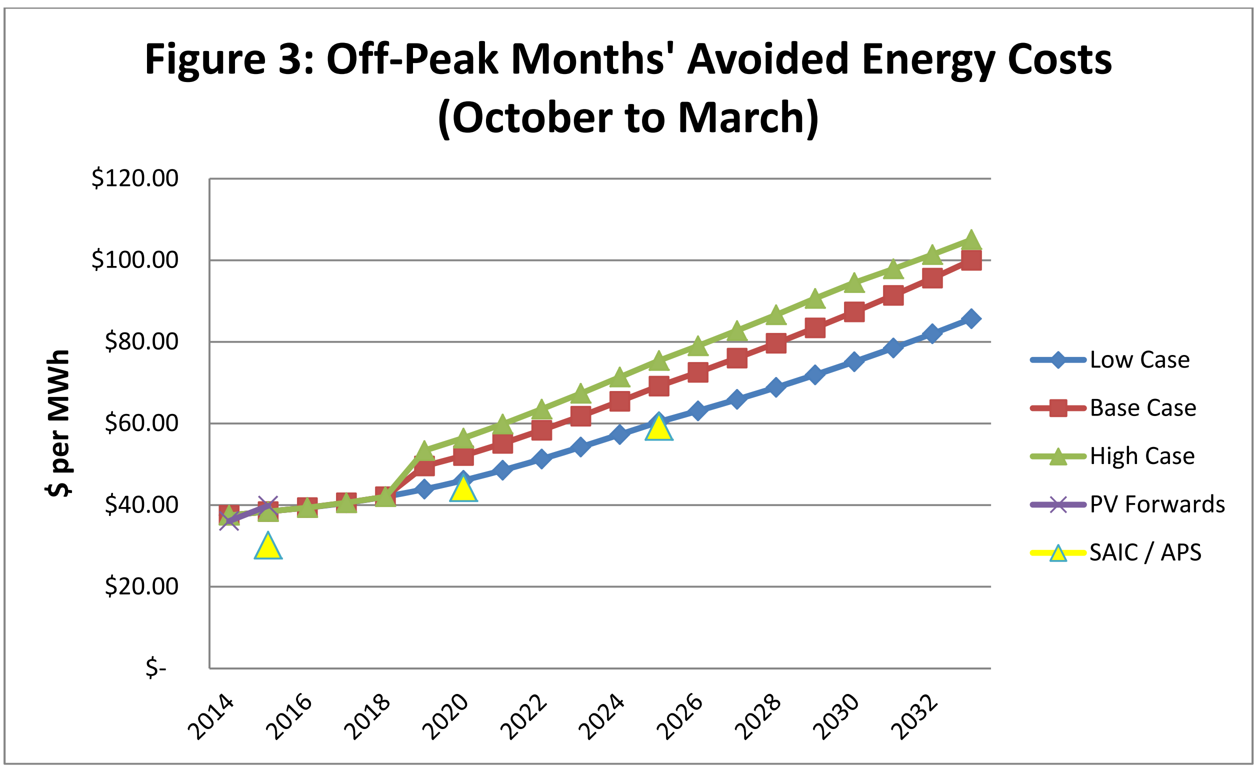


Table 2: *APS Avoided Energy Costs (including avoided line losses)*

Case	Methodology	Avoided Energy Costs *(20-year levelized c/kWh, 2014 $)*		
		Jun-Sept	Oct-May	Wtd. Annual
	Solar DG Output:	*35.5%*	*64.5%*	
Low	New CT (June-Sept) and CCGT (Oct-May). Zero GHG costs.	7.5 5.8		6.4
Base	New CT (June-Sept) and CCGT (Oct-May). Base GHG costs from 2012 IRP.	8.2 6.4		7.1
High	New CT (June-Sept) and CCGT (Oct-May). High GHG costs from 2012 IRP.	8.7 6.8		7.5

SAIC used the results of APS's confidential production cost modeling to estimate avoided energy costs; the SAIC results are shown in the second column of **Table 3,** below. These modeling results are too low to be credible as long-run avoided energy costs for the resources displaced by solar DG. The final column of Table 3 shows the marginal heat rates that are implicit in these results, based on the SAIC/APS natural gas and GHG cost forecasts. These heat rates are far lower than the heat ratesof even the most efficient new gas-fired resources, indicating that APS's modeling either (1) assumes that solar DG often displaces APS's existing coal-fired generation or (2) reflects only the low, short-run incremental costs of moving already-operating gas plants in the western U.S. from one loading point to another. Moreover, even if this modeling is realistic, it understates APS's avoided opportunity costs of selling its excess generation into the regional energy market at Palo Verde and other trading hubs, as shown in Figures 2 and 3. In sum, these results significantly understate the long-run energy costs avoided by solar DG resources which will completely displace the need for and the full costs of future gas-fired units.

Table 3: *SAIC / APS Avoided Energy Costs*

Year	Avoided Energy *(Nominal $/MWh)*	Gas Cost *$/MMBtu*	GHG Cost *$/MMBtu*	VOM *$/MWh*	Heat Rate *Btu/kWh*
	A	*b*	*c*	*d*	*1000*(a-d)/(b+c)*
2015	$30.17	$4.48	--	$5.00	5,618
2020	$44.24	$5.82	$0.83	$5.66	5,801
2025	$59.27	$7.66	$1.20	$6.40	5,967

b. Generation Capacity

The 2012 IRP finds that APS does not need new large-scale, fossil resources until 2017.[11] However, the 2012 IRP shows continued growth in energy efficiency and demand response programs and in distributed solar resources between 2012 and 2017 (see Table 2), such that the new demand-side resources will contribute 1,150 MW to meeting APS's peak demands in 2017. Solar DG, along with energy efficiency and demand response, thus contributes to deferring any

[11] *Ibid*., at pages 6 (Table 2) and 20. Also, APS March 20 presentation, at Slide 72.

resource need until 2017. As a result, solar DG installed before 2017 has greater value than just avoiding short-term energy costs. DG also hedges against events that could accelerate the 2017 need, such as unexpected increases in demand (from an accelerating economic recovery) or the loss of existing resources (for example, nuclear plant shutdowns such as the recent problems at the San Onofre plant in southern California).

Combustion turbines are the least-cost source of new utility-scale capacity. CTs are the long-term peaking resource typically displaced by solar DG, and arethe resource that APS expects to add in 2017. The Beck and SAIC Studies use the fixed costs of a new CT to calculate solar DG's generation capacity value. The CT fixed costs in the Beck Study were based on a CT capital cost of $1,088 per kW in 2008, times a fixed charge rate of 11.79% to convert to an annual levelized value.[12] The 2012 IRP cites CT capital costs in a range of $600 to $1,400 per kW, with heat rates from 8,900 to 11,900 Btu/kWh for a variety of brownfield and greenfield projects.[13] SAIC is using a CT capital cost of $1,136 per kW, plus $206 per kW in gen-tie transmission.[14] Following the Beck and SAIC Studies, we also have included (and updated) the fixed O&M costs and the El Paso Natural Gas pipeline reservation costs for a new CT built in APS's service territory. As shown in **Table 4**, we calculate that APS's levelized avoided capacity costs are $190.10 per kW-year in 2014 dollars.

The CT fixed costs are multiplied by the effective load-carrying capacity (ELCC) of PV generation. At the present level of solar PV penetration, this adjustment is 50% for a fixed array and 70% for an array with single-axis tracking. APS used these adjustments in the 2012 IRP to determine the firm capacity of solar resources, including resources that will be developed in the 2013-2015 time frame.[15] The resulting avoided generation capacity costs are shown in Table 4.

This analysis focuses on the value of solar to be developed in the next several years (2013-2015). The Beck and SAIC Studies indicate that, if solar penetration increases significantly, the capacity value of solar that is installed in 2020 and 2025 may be lower than today, as the increased amounts of installed solar resources shift APS's afternoon peak to later in the day. This possibility does not diminish the capacity value of solar installed today; indeed, the decline in capacity value in 2020 and 2025 will not occur unless substantial amounts of solar are installed over the next twelve years. Finally, the Beck / SAIC result that the capacity value of solar will decline over time assumes that the future will look like today, only with more solar. This is unlikely to be true. For example, other trends, such as hotter summers resulting from climate change, could increase future peak demands by more than expected, and offset the impact of solar additions. Customers also can respond to the changing mix of resources. If additional solar reduces the price for grid power in the afternoon, if those prices are conveyed in accurate price signals, and if customers have greater choice and control over when and from where they consume electricity, consumers will respond by shifting consumption from the evening to the afternoon – i.e. the opposite of what DR tries to achieve today – pre-cooling homes, running appliances remotely, and filling batteries in the afternoon instead of the evening.

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[12] Beck Study at Tables 5-8 and 6-1.
[13] 2 012 IRP, Attachment D.3.
[14] SAIC April 11, at 66 and 73.
[15] 2012 IRP, at Attachments D.1(a)(1) and D.3.

Table 4: *Avoided Generation Capacity Costs ($ per kW-yr in 2014$)*

Component	**Value**	*Source*
CT Capital Cost	$1,376 per kW	*SAIC April 11, at 66 and 73.*
x 11.17% carrying charge	$153.7	*SAIC April 11, at 66.*
+ Fixed O&M	$6.6	*SAIC April 11, at 73. Escalated at 2.5%*
+ Pipeline Reservation	$29.8	*EPNG Tariff, assumes 2.5% escalation*
Total	$190.1	*20-year levelized value*
PV ELCC – Fixed	50%	*Beck Study, at Table 5-2*
PV ELCC – Tracking	70%	*Beck Study, at Table 5-2*
Capacity losses	11.7%	*SAIC April 11, at 59.*
Avoided Costs		
Fixed array – South-facing	6.7 cents per kWh	*Assumes 1,575 kWh/kW; see SAIC April 11, at 57.*
Fixed array – West-facing	7.6 cents per kWh	*Assumes 1,400 kWh/kW*
Single-axis tracking	7.2 cents per kWh	*Assumes 2,060 kWh/kW*

c. Ancillary Services and Capacity Reserves

The Beck Study found that the intermittency of solar DG is unlikely to increase the ancillary services or operating reserves that APS must supply to ensure reliable service, given the geographically dispersed nature of DG systems.[16] The study did not consider, however, the fact that DG will result in a reduction in the loads that APS will serve, because the majority of DG output will serve the on-site load of the DG host customer or will run the customer's meter backward if power is exported. WECC reliability standards require control area operators to maintain operating reserves (spinning and non-spinning) equal to 7% of the load served by thermal generation. As a result, load reductions from DG will reduce APS's requirements to procure operating reserves. In addition, APS must maintain a capacity reserve margin of 15%. Thus, each kW reduction in APS's peak demand from DG will reduce the utility's capacity requirements by 1.15 kW. We model these avoided ancillary service and capacity reserve requirements as 7% of Base Case avoided energy costs from Table 2[17] and 15% of the south-facing avoided generation capacity costs from Table 4. These avoided ancillary service and capacity reserve costs are summarized in **Table 5**.

Table 5: *Avoided Ancillary Services and Capacity Reserve Costs*

Component	Cost Basis	Percentage	Value (cents/kWh)
Ancillary Services	Energy costs – from Table 2 (Base Case)	7% 0.5	
Capacity Reserves	Generation capacity costs – from Table 3	15% 1.0	
Total			1.5

16 Beck Study, at 5-22 to 5-27.

17 Based on an analysis of California Independent System Operator ancillary service costs used in the CPUC's E3 avoided cost calculator which is referenced in Footnote 3 above.

d. Transmission

The Beck Study reported that APS incurs $125 million in high-voltage transmission costs for every 400 MW increase in peak demand, and $7 million in lower-voltage subtransmission costs per 30 MW of load growth.[18] The SAIC April 11 presentation, at slide 63, shows $29.5 million in deferrable subtransmission costs for a 130 MW decrease in peak demand. In the long-run, solar DG combines with EE and DR resources to defer such costs even if, over a short-term period such as a three-year transmission planning cycle, none of these small-scale resources individually amounts to 400 MW or to the smaller amounts in specific areas that is required to defer subtransmission projects. Given that EE, DR, and DG resources will combine to reduce APS's peak demands by 1,150 MW in 2017, it seems clear that, in aggregate, these resources will avoid significant transmission costs on the APS system. Escalating these avoided transmission and sub-transmission costs to 2014 and using the current APS carrying charge of 11.05% for transmission yields a levelized avoided transmission cost of $65.14 per kW-year, as shown in **Table 6**. As with avoided generation capacity costs, we apply the solar ELCC values to the avoided transmission costs, in recognition that peak solar output does not necessarily coincide with system peak demands.

Table 6: *Avoided Transmission Costs*

Component	**Value**	*Source*
Transm ission Cost	$145 million	*Beck Study, at Table 4-1. Escalated to 2014 $ assuming inflation at 2.5% / year.*
÷ Capacity	400 MW	
+ Subtransmission Cost	$29.5 million	*SAIC April 11, at 63.*
÷ Capacity	130 MW	
Transmission costs avoided	$589 per kW	
x 11.05% carrying charge	$65.13 per kW-yr	*SAIC April 11, at 66.*
PV ELCC – Fixed	50%	
PV ELCC – Tracking	70%	
Avoided Costs		
Fixed array – South-facing	2.1 cents per kWh	*Assumes 1,575 kWh/kW; see SAIC April 11, at 57.*
Fixed array – West-facing	2.3 cents per kWh	*Assumes 1,400 kWh/kW*
Single-axis tracking	2.2 cents per kWh	*Assumes 2,060 kWh/kW*

e. Distribution

The Beck Study examined a range of possible DG impacts on distribution system costs. These impacts are more location-specific than the effects of DG on the generation or transmission systems. The Beck Study concluded that distribution capacity cost savings are possible if demand reductions from DG exceed load growth on distribution feeders or substations, and if solar

[18] *Ibid.*, at 4-12.

DG can be targeted to specific locations where circuits would otherwise need an upgrade.[19] The study valued these reductions using a distribution avoided cost of $115,000 per MW of DG ($115 per kW).[20] SAIC has now backed away from these results, arguing that it could identify only 5-9 circuits on which installed PV capacity reduced the circuit peak to below the 90% of capacity threshold at which the utility begins to plan an upgrade.[21] Yet this appears to be an appreciable fraction of the 30-40 circuits that APS upgrades each year.[22] Moreover, even on a circuit whose loading is below the 90% threshold today, PV can reduce the peak loading and defer the future date when that circuit's loads exceed the 90% threshold, a date that may be beyond the current distribution planning period but well within the lives of the installed PV systems. The Beck Study reported that 50% of the feeders modeled show potential for reducing peak demand and deferring capital improvement projects.[23] Avoided distribution capacity costs can be valued using the same approach applied to transmission costs in Table 5, with the additional assumption that PV can avoid distribution costs on 50% of circuits. **Table 7** presents these results.

Table 7: *Avoided Distribution Costs*

Component	**Value**	*Source*
Distribution Costs Avoided	$133 per kW	*Beck, at 3-13. Escalated to 2014 $ assuming 2.5% inflation per year.*
x 11.05% carrying charge	$14.70 per kW-yr	*SAIC April 11, at 66.*
PV ELCC – Fixed	50%	
PV ELCC – Tracking	70%	
Fraction of distribution circuits with avoidable costs	50%	
Avoided Costs		
Fixed array – South-facing	0.2 cents per kWh	*Assumes 1,575 kWh/kW; see SAIC April 11, at 57.*
Fixed array – West-facing	0.3 cents per kWh	*Assumes 1,400 kWh/kW*
Single-axis tracking	0.3 cents per kWh	*Assumes 2,060 kWh/kW*

f. Environmental

With the exception of greenhouse gas emissions, the Beck and SAIC studies have not quantified any of the environmental benefits of renewable generation, such as reductions in criteria air pollutants (SO_2, NO_x, and PM 10) and decreased water use for electric generation. APS did quantify these benefits in the 2012 IRP, however. The utility calculated both the reduced emissions of these pollutants and the lower water use, per MWh of renewable generation,[24] and

[19] *Ibid*, at 3-33.
[20] *Ibid*, at 3-13.
[21] SAIC April11, at 61-62.
[22] APS stated at the April 11 workshop that it upgrades "a few percent" of its 1,351 distribution circuits each year.
[23] Beck Study, at 3-26.
[24] 2012 IRP, at 89-90.

included estimates of the dollar value of such reductions.[25] **Table 8** summarizes these environmental benefits.

Table 8: *Avoided Environmental Costs*

Category	**Avoided Emissions** *(tonnes or AF per GWh)*	**Value** *(20-year levelized $ per tonne or AF)*	**Avoided Cost** *(20-year levelized $ per MWh)*
Criteria air pollutants			
SO_2 0.0023		$11,144	$0.025
NO_x 0.0461		$6,926	$0.319
PM 10	0.0125	$1,642	$0.021
Water	0.9728 $1,114	per AF	$1.084
Total ($ per MWh)			$1.449
Total (cents per kWh)			0.1

g. Avoided Renewables Costs

Solar DG helps APS to meet Arizona's Renewable Energy Standard (RES) requirements. The Arizona RES regulations include a requirement that APS must procure renewable generation equal to a certain percentage of its sales, with the percentage increasing from 4.0% in 2013 to 10% in 2020 and 15% by 2027. The RES requirement also provides that, after 2011, 30% of the new renewable generation meeting the RES standard must be DG resources. Pursuant to Arizona Corporation Commission (ACC) Decision No. 71448. APS also must procure an additional 1,700,000 MWh of incremental renewable generation by December 31, 2015.[26] The Beck Study did not attribute any value to DG's contribution to meeting APS's RES requirements. However, because it is customers who make investments in DG resources, not APS, such customer-owned resources allow the utility to avoid the higher capacity-related costs of renewable power.

APS has also argued that solar DG does not avoid the costs of other renewable resources because APS already has procured adequate renewables to meet its RES requirement. However, all of these resources are not yet on-line, so solar DG may hedge against the failure of some of the utility-scale renewables with which APS has contracted. Moreover, APS itself recognizes that, in the long-run, it may have to procure renewables beyond today's RES requirements. The 2012 IRP includes an Enhanced Renewable Portfolio which assumes that APS increases the contribution of renewable energy to 30% of retail sales by 2025 and meets 90% of load growth with emissions-free resources. In addition to further reductions in emissions of greenhouse gases and criteria air pollutants, there are economic reasons to procure additional renewables. For example, the 2012 IRP notes that, in both the intermediate- and long-terms, "renewable resources have the ability to diversify the overall portfolio of resources and provide mitigation against the

25 *Ibid*, at 135-136. The criteria air pollutant costs were based on a National Academies of Science study specific to APS's power plants. The value of incremental water savings reflected the costs for treated effluent from an APS power plant.

26 *Ibid*, at 141-143.

inherent price volatility risks associated with a natural gas-dominated energy mix."[27]

Renewable generation also results in a number of difficult-to-quantify benefits, including:

- **Price mitigation benefits.** Lower demand for electricity (and for the gas used to produce the marginal kWh of power) has the broad benefit of lowering prices across the gas and electric markets in which APS operates.[28]
- **Grid security.** Renewable DG resources are installed as many small, distributed systems and thus are highly unlikely to fail at the same time. They are also located at the point of end use, and thus reduce the risk of outages due to transmission or distribution system failures. This reduces the economic impacts of power outages.
- **Economic development.** Renewable DG produces more local job creation than fossil generation, enhancing tax revenues.

We assume that the additional cost of renewable generation provides a proxy for these benefits. These benefits have been calculated separately in at least one study, which estimated these benefits collectively to be from \$100 to \$140 per MWh in several eastern U.S. markets.[29]

For the APS system, the 2012 IRP includes APS's estimates of the incremental cost of renewables. The Enhanced Renewable scenario in the 2012 IRP features additional purchases of renewables in the 2017-2026 time frame, totalling 4,532 GWh of additional renewable generation by 2026 compared to the Base case (about 500 GWh per year in additional renewable generation).[30] The 2012 IRP includes annual revenue requirements for both the Base and Enhanced Renewable scenarios; the difference between these revenue requirements allows one to calculate the annual cost premium for the incremental renewables in the latter scenario.[31] The cost premium for these purchases averages \$46.55 per MWh from 2017-2026 (\$45.27 per MWh on a 10-year levelized basis).[32] We use this premium as the measure of the costs which APS will avoid if APS's customers invest in solar DG, reduce the future need for APS to purchase additional wholesale renewable generation, and provide the benefits listed above. This appears to us to be a conservative estimate of the value of additional customer-driven renewable generation on the APS system over the next 20 years.

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[27] *Ibid.*, at 64.

[28] For example, a Lawrence Berkeley National Lab study has estimated that the consumer gas bill savings associated with increased amounts of renewable energy and energy efficiency, expressed in terms of \$ per MWh of renewable energy, range from \$7.50 to \$20 per MWh. Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (January 2005), at ix, http://eetd.lbl.gov/EA/EMP .

[29] Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2.

[30] 2012 IRP, at Attachment F.1(a).

[31] *Ibid*, at Attachment F.1(b).

[32] Modeling of the RPS program in California produced a similar long-term cost premium for renewable generation. See the E3 avoided cost calculator referenced in Footnote 3.

3. Costs of Solar DG

The primary costs of solar DG are the retail rate credits provided to solar customers through net metering, i.e. the revenues that the utility loses as a result of DG customers serving their own load. Data responses from APS to the ACC staff in the 2013 RES case[33] include calculations of the 20-year levelized retail rate credits (i.e. the lost revenues for APS) resulting from DG, as well as the costs of the current incentives paid to customers who install DG. In the technical workshops, APS also has provided Vote Solar with its estimates of residential and commercial lost revenues. For residential customers, the retail rate credits amount to 15.5 cents per kWh; for business customers, the credits are 7.1 cents per kWh.[34] APS has assumed a retail rate escalation of 2.5% per year and an 8% discount rate.[35] These assumptions produce 20-year levelized retail rate credits of 19.7 cents per kWh for residential and 9.0 cents per kWh for commercial (2014 $). Assuming the current mix of residential and commercial systems, the average rate credit is 13.7 cents per kWh.

With respect to incentive costs, the 20-year levelized cost of the current 10 cents per watt residential upfront incentive is 0.6 cents per kWh. We understand that APS has proposed to eliminate these residential incentives, so they may be zero in the future. APS also has eliminated business incentives, except for school and government projects.

Finally, we add an estimate of solar integration costs using a recent study which APS commissioned which estimated integration costs of $2 per MWh in 2020 and $3 per MWh in 2030.[36] We assume that these costs scale to other years as a function of gas costs.

Table 1 and Table 9 summarize all of these costs of DG for APS's ratepayers.

Table 9: *Costs of Residential and Commercial Solar DG on the APS System*

Cost categories	**Costs** *(20-year levelized cents per kWh)*		
Residential		Commercial	Average
Distribution of systems	*44%*	*56%*	*100%*
Lost retail rate revenues	19.7	9.0	13.7
DG incentives	0 to 0.6	0 to 2.3	0 to 1.6
Integration costs	0.2	0.2	0.2
Total Costs	**19.9 to 20.5**	**9.2 to 11.5**	**13.9 to 15.5**

[33] ACC Docket No. E-01345A-12-0290. See APS response to Data Request Staff 1.
34 APS produced these estimates in 2012, so we assume they are in 2012 $.
[35] Response to Data Request Staff 1.4.
[36] Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

4. The Context for this Cost / Benefit Analysis

The Beck and SAIC Studies calculate the benefits of DG – i.e. the "value of solar." These benefits could be used in a cost-benefit evaluation of solar DG, such as is presented in the report. The Beck and SAIC Studies do not discuss the cost side of the equation, or attempt to apply any of the standard cost-effectiveness tests to DG. We assume that APS will use a new calculation of the benefits of DG in a ratepayer impact test, such as the one presented in this report.[37] The conclusion of this report is that solar DG with net metering is cost-effective for non-participating ratepayers in APS's service territory.

We emphasize that the ratepayer impact perspective should not be the only one which policymakers examine in deciding on future policies affecting solar DG in Arizona. The RIM test often is considered the most rigorous of the cost-effectiveness tests for demand-side resources; passing the RIM test with a benefit / cost ratio greater than 1.0 means that there are "no losers" from a demand-side resource. Nonetheless, a full analysis of solar DG as a resource also should consider additional cost-effectiveness perspectives, such as societal, total resource, participant, and program administrator tests.[38] Other demand-side programs typically are evaluated from these multiple perspectives, and policymakers should take a similarly broad view in assessing distributed generation programs.

[37] The APS discovery responses to the Arizona Commission staff in the last APS Renewable Energy Standard (RES) case appear to include such ratepayer impact calculations, although the benefits of DE are redacted.

[38] For example, a full cost-effectiveness report on the California Solar Initiative program can be found at ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/csi/CSI%20Report_Complete_E3_Final.pdf .