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Arizona Corporation Commission
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Docket Control
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Re: Value and Cost of Distributed Generation (Including Net Metering)
Docket No. E-00000J-14-0023

Arizona Public Service Company (APS or the Company) appreciates the opportunity to provide comments on the relevance and significance of the potential distributed generation (DG) benefit and cost categories as set forth in Staff's initial letter to stakeholders dated January 27, 2014. The categories of benefits and costs listed by Staff build upon the discussions held by APS and solar industry stakeholders in the 2013 Technical Conferences. Those conferences focused on the costs and benefits of distributed solar and the resulting shift of costs, through net metering, from participating customers to non-participating customers. As a result of the Technical Conferences and the net metering docket that followed, the Commission acknowledged the existence of a cost shift inherent in current policy and took steps to begin mitigating this cost shift.

The evaluations and studies that were discussed as part of the Technical Conferences provided much of the information surrounding the value and cost quantification of DG that Staff requests in this docket. **Attachment A** is a matrix of APS's comments on the relevance and significance of the categories of DG value and cost in Staff's request. These comments reflect the Company's position on DG costs and benefits, appropriate valuation processes and calculation methods as expressed in the Technical Conferences.

In addition to the specific categories of DG costs and benefits outlined in Staff's letter and Attachment A, the Company proposes that the workshops in this docket address the following concepts:

I. **A robust and modern electric grid is necessary for technologies like DG to emerge, and in fact, such technologies are simply not viable without the grid;**

II. **The cost of DG is different than its value, and rates should be based on costs and fairly allocated amongst customers; and**

III. **Rate design done correctly will enable and sustain current and emerging technologies in Arizona.**

APS supports the deployment of DG in Arizona. The Company includes these resources in its distribution system and resource planning efforts. Customers are both consuming and producing energy in new and innovative ways, and will continue to do so as new technologies emerge in the electric industry. APS supports this trend and with the appropriate rate design, any and all forms of DG can be an integral part of this future.

I. A robust and modern electric grid is necessary for new technologies like DG to emerge, and in fact, such technologies are not viable without the grid.

The Commission recognized that the workshops in this docket need to consider the grid and how it relates to customer-sited technology.[1] Study after study has shown that the grid is the foundational backbone for DG and other technologies. The electric grid provides stability and reliability for DG and other emerging technologies and innovations in the form of voltage regulation, power quality, frequency regulation, real-time balancing of load and supply, and other services that can only be supplied by the grid. The grid provides customers with the flexibility to adopt DG systems—and other technologies such as electric vehicles—without impacting essential services and consumer lifestyles. The grid ensures that energy will still be available at night, in the rain and if a DG system is being maintained or fails. The grid is a path for excess electricity to flow back to the grid, avoiding wasted energy and preventing potential damage to customer equipment. In fact, without a grid, excess energy can turn into heat, causing fires and potentially serious safety hazards. The grid also allows customers the flexibility to add or remove load as desired without prior planning. And perhaps most importantly, without the grid, many technologies—like rooftop solar—simply do not function.

For example, consider a solar photovoltaic (PV) rooftop DG system in the desert climate of Arizona during the summer afternoon hours. However, an air conditioner requires a strong momentary flow of current during the split second that the appliance starts up. Without grid connectivity, a central air conditioner relying only on a typical rooftop PV system would not start up at all.[2] In other words, even when the sun is at its highest, the grid is what customers rely on. Current technologies like PV can only supplement grid-provided electric services.

The value of the electric grid can also be conceptualized by considering the equipment and technologies that would be required to replace the functions of the grid if a customer were to disconnect completely. The independent, non-profit Electric Power Research Institute

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[1] "The workshops shall be based upon the Commission's determination of the presence of a cost shift from DG customers to non DG residential customers, and shall provide for the Commission's future full consideration of the net metering cost shift issue, the development of a method by which the value of DG can be considered in balancing the public interest, and the evaluation of the role and value of the electric grid as it relates to rooftop solar, other forms of distributed generation, and customer-sited technology generally." Decision No. 74202 at 30, lines 14-20 (emphasis added).

[2] This voltage regulation requirement is known as "in-rush" current.

(EPRI) addressed this concept in a study published this month.[3] In that study, EPRI states that a residential PV customer would need to add the following to provide the services currently supplied by the electrical grid:

- Additional PV modules beyond the requirements for offsetting annual energy consumption in order to survive periods of poor weather;
- Multi-day battery storage with a dedicated inverter capable of operating in an off-grid capacity;
- Backup generator on the premises designed to operate for 100 hours per year; and
- Ongoing operations and maintenance, including inverter replacements and generator maintenance.[4]

EPRI estimates that the costs for these technologies would be four to eight times more expensive than the cost for the same services from the existing electrical grid. EPRI also notes that even if such investments were made, the customer would experience much lower reliability and quality of electrical service. That the grid provides immense value—a fact beyond doubt—is not the only key conclusion to be derived from EPRI's study. A critical fact for the Commission and stakeholders in this docket to consider is that not only does the grid provide value in and of itself, but technologies like rooftop solar have limited value without the grid. Clearly, the grid has substantial value above and beyond its cost to utility customers.

The electric grid is the critical infrastructure that enables the use and development of distributed energy resources and other technologies as a whole. The rooftop solar industry knows that DG simply cannot operate without the grid. For example, the Solar Alliance has stated that "without a connection to the common utility infrastructure of the regulated public service corporation the [rooftop] solar facilities...cannot operate."[5] A DG customer uses grid services on a continuous, ongoing basis.

Customer choices around energy are evolving, and a robust and modern grid will be essential for customers to continue having choices in the future. The modernized grid will enable higher penetration of local DG resources and reduce the risk of grid instability due to the intermittence of these resources. Advances in grid-dependent technology and evolving grid support needs are making transmission and distribution systems more critical than ever before.

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[3] Electric Power Research Institute (EPRI), The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources, February 2014. This study can be accessed at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733.

[4] *Id.*, p. 23.

[5] *Application for a Declaratory Order That Providers...Would Not Be Public Service Corporations,* Commission Docket No. E-20633A-08-0513. In addition, Lyndon Rive, the CEO of Solar City, testified before the Commission that "the customer must remain connected to the utility grid for the majority of their electricity needs." *Pre-filed Direct Testimony of Lyndon Rive on behalf of Solar City,* Docket No. E-20690A-09-0346. In the same docket, Solar City's Application stated that "the customer must remain connected to the grid [even if they install PV]." *Application of Solar City for a Determination That... it is Not Acting as a Public Service Corporation...,* Docket No. E-20690A-09-0306.

Ralph Cavanagh, co-director of the energy program at the National Resources Defense Council (NRDC), recently recognized this reality, stating "To provide [cleaner energy services], [utilities] need to invest in updating and reforming the transmission grid to maximize the benefits of energy efficiency and renewables such as wind, solar, and geothermal."[6] For customers to have the opportunity to interconnect current and future customer-sited technologies, the grid must be robust and must be able to integrate new technology seamlessly and reliably. If new studies must be performed every time a new technology is invented because it is unknown whether the grid is resilient enough or how other installed technologies might be affected, we as a society will be unable to capitalize on one of our greatest strengths—the capacity to rapidly develop and deploy innovative technology.

II. The cost of DG is different than its value, and rates should be based on costs and fairly allocated amongst customers.

Distributed generation provides important value to utilities, customers and society. And through these workshops, APS looks forward to further exploring the value of the grid to customers (including DG customers) and society. **But in this proceeding, it is critical to distinguish between value and cost.** Value can be defined as "that quality of a thing according to which it is thought of as being more or less desirable, useful, estimable, important, etc."[7] By contrast, cost can be defined as "the amount of money, time, effort, etc. required to achieve an end."[8] Value considerations properly inform planning and policy decisions—forward looking determinations reflect that which is important. But in a regulated environment, rates are set to recover costs and are not intended to (and cannot accurately) capture value. That is as true for a solar resource as for a gas, nuclear or coal plant. Although some argue that solar rates should fully recognize value, social pricing cannot be used to offset, and is fundamentally incompatible with, cost-based rates.

Staff recognized this incompatibility in its Memorandum and Proposed Order in the APS Net Metering Cost Shift Solutions docket. There, Staff noted that two forms of value are inherent in DG systems: Objective Values, those benefits that can be measured and quantified; and Subjective Values, which are not easily measurable. Staff considered Subjective Values to be fundamentally a matter of public policy because quantifying them requires assigning value without specific measurement. APS agrees. Electric rates that compensate customers for societal benefits should arise out of deliberate policy decisions.

Moreover, even though Objective Values can be calculated, not all are appropriately recovered through rates. During the Technical Conferences, some stakeholders attempted to quantify a wide range of benefits of solar rooftop DG, settling on a value of solar DG of approximately 24 cents/kWh in the APS service territory.[9] Any attempt to value the benefits of DG solar, however, must begin with acknowledging that the same benefits are also available by deploying central solar generation at the distribution level—independent of

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[6] Ralph Cavanagh as quoted in IHS The Energy Daily, Thursday, February 13, 2014.
[7] Webster's NewWorld Dictionary, Second College Edition, 1982.
[8] *Id.*
[9] Crossborder Energy, The Benefits and Costs of Solar Distributed Generation for Arizona Public Service, May 8, 2013.

ownership. Importantly, central solar generation can be obtained at far less cost. APS estimates that the wholesale market price for central solar resources that can be interconnected at the distribution level is between 7 and 9 cents/kWh, and is decreasing rapidly.

Central solar provides comparable benefits to rooftop solar in avoided distribution infrastructure costs, reduced water costs, avoided fuel costs, and environmental attributes, among others. In fact, central solar offers certain benefits not provided by distributed solar resources, such as the ability to optimize capacity and transmission investment by carefully siting central solar generation at load centers. Because of the similarities between these solar generation technologies, customers should not pay more for the benefits provided by rooftop solar than they would otherwise pay for the same benefits provided by central solar stations.

APS and stakeholders addressed the value of both fixed and single-axis tracking solar PV in the January 2009 report entitled *Distributed Renewable Energy Operating impacts and Valuation Study*. The potential value of fixed solar PV systems was updated for use in the Technical Conferences in the May 2013 SAIC study entitled *2013 Updated Solar PV Value Report*, included here as Attachment B. In the Company's view, discussions in this docket should draw upon the value determinations in these studies and in the Technical Conferences.[10]

III. Rate design done correctly will enable and sustain current and emerging technologies in Arizona.

A diverse and dynamic energy system is clearly the direction for the future. A robust and modern electrical grid will enable that future. But the future of all forms of grid-dependent technologies and innovations will only be promising if we craft a more modern rate structure that appropriately reflects the essential nature of the grid and the services it provides. Utility rates must reflect the cost of maintaining, supporting and modernizing the grid. Customers are increasingly utilizing the grid to support DG technologies, and must provide reasonable compensation to the utility for the services they use. This is one implication that flows from the Commission recognizing the cost shift. It is not fair or sustainable to require non-participating customers to pay higher rates so that other customers can install new technologies.

To ensure that DG and other technologies flourish, and that the grid is able to support these technologies, rate design must evolve from current-day commodity pricing. Under current rate designs and net metering policy, DG customers shift grid costs to non-participating customers. APS provided significant and detailed information regarding basic ratemaking principles and the deficiencies in current rate design during the Technical Conferences and in the Company's net metering testimony. The Company recognizes that

[10] It is important to note that no solar valuation methodology or resulting value of solar has been offered with sworn testimony or subjected to cross examination in an evidentiary hearing. The Company believes such a proceeding would be necessary before actual customer rates were set with any specific value of solar methodology.

fundamentally changing years of accepted rate designs may be challenging, and that there is no one simple answer that perfectly addresses the deficiencies without considerations or limitations. If rate design is not modernized, however, grid-dependent technologies like DG will not grow sustainably.

IV. Potential Speakers

Per Staff's request, APS believes the following experts would provide valuable information, experience, and viewpoints as presenters in workshops:

Robert L. Davis, Principal and Executive Consultant, nFront Consulting.

Arshad Mansoor, Senior Vice President of the Research and Development Group, EPRI.

Additionally, APS would be happy to contact any presenters from the 2013 Technical Conferences or make available the Company's in-house subject matter experts to present on relevant topics at each of the workshops.

Should Staff be interested in having any of these individuals participate as presenters in this process, please contact my office. I will be happy to assist by communicating with each speaker to arrange schedules.

APS looks forward to participating with Staff, Commissioners and stakeholders in workshops and discussions regarding both the valuation of DG and the value of the grid.

Sincerely,

Thomas A. Loquvam

TAL/bgs

cc: Commissioner Bob Stump
Commissioner Gary Pierce
Commissioner Brenda Burns
Commissioner Susan Bitter Smith
Commissioner Robert L. Burns
Steve Olea
Terri Ford
Lyn Farmer

Attachment A

Attachment A

Potential DG Value and Cost Categories

Applicable and Quantifiable for Utility Ratemaking			
Cost Category			**Considerations**
1	Capacity	Distributed Energy Capacity Value (MW)	Capacity value of DG on the APS system is affected by several factors, including its intermittency, variability, and coincidence with the system peak. These factors are captured by the effective load carrying capability (ELCC) methodology that APS and others use to estimate DG capacity value. D G penetration is also an important factor because of the diminishing return effect: higher DG penetration results in lower capacity value as APS's peak shifts towards sunset.
2	Capacity	Avoided Generation Capacity (new generation $)	Avoided generation capacity is determined by comparing two load and resource plans: A Base Case with no DG forecasted to be installed and a DG Case with a certain DG forecast to be included in the system. The comparison results in a schedule of (typically) combustion turbines to be deferred over time due to the installation of DG. This process is fully described in the SAIC Report[1]. The related dollar savings are tied to the costs of whatever generating units are deferred due to DG. As noted in the Distributed Energy Capacity Value section above, the capacity value of DG declines as the penetration of DG increases.
3	Capacity	PV System Orientation	The value of PV system orientation is included in distributed capacity value and avoided fuel and purchase power (items 1 above and 11 below). There are three major factors that determine the annual production of a PV system; tilt angle of the panels, orientation to the sun, and overall shading factor of the sun. Optimal Arizona conditions for maximum annual energy production would be panels installed at 180 degrees azimuth (due south), a tilt angle of 33 degrees (equal to the degrees latitude of the geographic installation), and full exposure to the sun (no shading). Generally, when PV systems are installed on a customer's home, they are constrained to the orientation of the home, and the existing angle of the roof. Rates incent customers to produce as many kWh as possible. Utilities have times of the day or year where production and/or capacity at a specific location is of a greater or lesser value, and is not reflected in the actual level of compensation a customer receives. System specific generation profiles would have to be evaluated, modeled, and compared to the resource need or system operational benefit for the entire year/life to determine the appropriate commensurate value. To be practical, "typical orientation" based on empirical data should be used in estimating DG solar energy production and its benefits to the system.
4	Grid Support Services	Ancillary Services	DG may increase requirements for some ancillary services such as regulating reserves, thus increasing utility operating costs. Certain ancillary services are in included in integration costs (item 10 below).

[1] SAIC. *2013 Updated Solar PV Value Report,* May 10, 2013.

Attachment A

Potential DG Value and Cost Categories

Applicable and Quantifiable for Utility Ratemaking			
Cost Category			**Considerations**
5	Grid Support Services	- Reactive Supply & Voltage Control	Typically variable energy resources such as DG do not provide the capability to provide controllable reactive support and voltage control. With higher levels of penetration, the amount of traditional generation that will be online during the day will be lower. Therefore, additional reactive support and voltage control equipment may be needed adding to integration costs..
6	Grid Support Services	- Frequency Response	DG does not provide any benefit for frequency response. As penetration levels increase, and the amount of traditional generation that is online during the day decreases, the ability to meet NERC reliability standards for frequency response will be more difficult to meet. Other options for frequency response will be needed.
7	Grid Support Services	- Energy Imbalance	Due to the intermittent nature of DG resources, more flexible reserves will need to be maintained on the system to ensure reliability and compliance with NERC standards. The value for ancillary services items 4 -9 are in included in integration costs.
8	Grid Support Services	- Operating Reserve	Due to the minute-to-minute variability in solar output, utilities will need to increase their operating reserves in order to comply with NERC's Control Performance Standard 2 (CPS2) requirements, thus imposing additional operating costs on the system. The costs of integrating solar and other DG into the APS system are the costs of additional spinning reserve and regulation requirements imposed on the APS system in order for it to be in compliance with CPS2. A process and methodology to monetize these solar integration costs are described in the Solar Photovoltaic (PV) Integration Cost Study prepared for APS by Black & Veatch[2].
9	Grid Support Services	- Scheduling Forecasting	It is difficult to forecast the output of DG. When clouds are present, the output varies widely and requires traditional generation resources to be available to replace the lost output. Few tools exist today to accurately forecast DG output as each DG installation is a different orientation to the sun. In order to purchase the correct quantity of natural gas on a day-ahead basis, forecasting the impact of DG on load is important. Errors in forecasting can result in less efficient operations and increased gas pipeline imbalance charges.

[2] Black & Veatch. *Solar Photovoltaic (PV) Integration Cost Study – Prepared for Arizona Public Service Company.* November 2012.

Attachment A

Potential DG Value and Cost Categories

Applicable and Quantifiable for Utility Ratemaking

Cost Category			Considerations
10	Grid Support Services	DG System Integration Costs	As the level of PV installations increases, additional capital investments and operating expenses will be required in order to maintain system reliability and power quality standards. Voltage management on distribution feeders, especially during spring and fall, when customer usage is low and PV production is high, will need to be managed dynamically along the distribution feeders to ensure proper delivery voltages are maintained throughout the length of the feeder. With the growing number and location of generation sources, advanced relaying and protection schemes will be needed to ensure power flows are coordinated and managed properly. Specific feeder modeling will be required to identify potential system impacts, as well as their corresponding mitigating solutions. This increased total level of investment and their on-going maintenance expenses, as well as the supporting ancillary services, will need to be accounted for and factored into the value proposition of DG and/or the grid and appropriated accordingly.
11	Avoided Cost/Financial Risk	Avoided Fuel/Purchase Power Costs	The best way to estimate avoided fuel and purchased power costs is by using a production cost (also called economic dispatch) model. In such a model, generation plants are dispatched according to their economics to meet expected system loads. This way, the effects of DG on the entire system are fully accounted for. Using any other types of models to estimate avoided fuel costs will result in missing the re-dispatch effects on the various types of resources included in the system. APS uses the PROMOD model for this type of analysis. This process is fully described in the SAIC Report.

Potential DG Value and Cost Categories

Applicable and Quantifiable for Utility Ratemaking

Cost Category			Considerations
12	Avoided Cost/Financial Risk	Avoided Line Losses	APS includes avoided line losses as a standard component of its avoided energy and capacity calculations (items 1 and 11 above). Average system line losses are the most appropriate values to use in the calculation of avoided energy and capacity. The average system line loss used in the SAIC Report is empirically verifiable, previously reported and consistent with the approach utilized in the IRP process. In a recent study prepared by Xcel Energy Services[3] to address the costs and benefits of distributed solar photovoltaic generation ("DG", or "DSG"), 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." 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. An average line loss approach seems to be the most reasonable based on the data and analysis available to-date.
13	Avoided Cost/Financial Risk	Avoided/Delayed Transmission System Investment	APS considers two types of transmission investments that could be deferred by DG: (1) Transmission interconnection costs related to avoided generation plants, and (2) Major transmission projects proposed in APS's Ten-Year Transmission Plan. Avoided interconnection costs are accounted for in estimating avoided generation capacity costs. For potential deferral of major transmission projects, effects of DG on the hourly system loads are calculated and compared with load levels expected of the proposed transmission projects included in the Ten-Year Transmission Plan to determine if their timing could be delayed. This process is described in the SAIC Report.
14	Avoided Cost/Financial Risk	Avoided/Delayed Distribution System Investment	Historical data on locations of existing DG installations can be analyzed to determine if DG would be sufficient enough to defer planned upgrades on any existing distribution feeder in the APS system. Applying these relationships to future expected penetration levels would provide a basis for estimating the amount of distribution system investments that might be avoided. This process is described in the SAIC Report.

[3] Xcel Energy Services, Inc. *Costs and Benefits of Distributed Solar Generation to the Public Service Company of Colorado System - Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223*, May 23, 2013.

Potential DG Value and Cost Categories

Applicable and Quantifiable for Utility Ratemaking

Cost Category			Considerations
15	Avoided Cost/Financial Risk	Avoided Renewable Energy Standard Cost	To the extent that APS is at or below compliance in meeting its RES requirements, the effect of displacing one type of renewables with another can be considered. The best approach for determining the avoided costs for renewable energy resources is to simply compare like-for-like -- in the absence of a certain amount of DG energy, what alternative renewable resources would be needed to fulfill the requirements of the RES and at what incremental cost (over and above the avoided cost of conventional generation)? To the extent that the utility is above compliance with the RES requirement, these avoided RES costs would naturally be zero. To the extent that the utility is below compliance, the upper bound on the combined avoided capacity and energy costs of conventional generation plus the avoided RES compliance costs appears to be the current cost of utility-scale solar of approximately 7-9 cents/kWh.
16	Avoided Cost/Financial Risk	Avoided Utility Administration Costs	DG adds administrative costs. APS must ensure safe reliable interconnection and must complete compliance and production reporting.
17	Avoided Cost/Financial Risk	Avoided Variable O&M Costs	Avoided variable O&M costs are best estimated by using the same method used to estimate avoided fuel and purchased power; that is, via the use of a production cost model. APS uses the PROMOD model as fully described in the SAIC Report.
18	Avoided Cost/Financial Risk	Avoided Fixed O&M Costs	Avoided fixed O&M costs are not dependent on the system dispatch; therefore, they could be estimated by using the fixed O&M associated with the conventional generation resource appropriately selected to be the avoided capacity. Avoided fixed O&M is included in avoided capacity (item 2 above).
19	Environmental	Water Consumption	Water consumption is included in the avoided variable O&M costs (item 17 above).
20	Environmental	Cost of Environmental Compliance	Potential environmental benefits provided by solar DG are quantified by using the PROMOD Model as fully described in the SAIC Report. Specifically, environmental benefits used in the SAIC Report are related to the cost of CO2 and SO2 emission included in APS's Integrated Resource Plan. This category could only be considered in ratemaking if a federal carbon tax is implemented. To the extent a federal carbon tax does not materialize, the value for CO2 would be zero. SO2 values are estimates based on market trading activity. Benefits for avoiding NOX control costs are included in avoided capacity costs. APS does not explicitly add costs for externality values. The cost of environmental compliance is included in avoided energy and capacity (item 2 and 11 above).
21	Social	Ratepayer/Consumer Interest	The ACC must find that rates are just, reasonable and in the interest of all customers. The relevant issues are included in rate payer cross-subsidization (item 22 below).

Attachment A

Potential DG Value and Cost Categories

Applicable and Quantifiable for Utility Ratemaking

Cost Category			Considerations
22	Social	Ratepayer Cross-Subsidization	Ratepayer cross-subsidization is the key measurement of the net benefits of distributed generation. It tests whether customers that adopt DG pay an adequate and fair share for the services that they still take from the utility, or whether those costs are shifted to other customers. The typical approach to this test involves a determination of the services that DG customers still take from the utility, the bill savings or amount that DG customers no longer pay for utility services, and the utility cost savings that results from DG. An alternative approach to this rate payer cross-subsidization test would be to directly determine the services that DG customers are still taking from the utility and compare the costs of those services to the DG customer's remaining utility bills. If the DG utility bills cover those costs of services, then there is no cost shifting to other customers. However, if the DG bills are less than the costs for the services that they are taking form the utility then the net amount would be shifted to other customers. This approach is straight forward and would avoid the need for any estimation of the value of DG. Pursuant to Commission Decision No. 74202 (December 3, 2013), the Commission has acknowledged the existence of a cost shift.

Attachment A

Potential DG Value and Cost Categories

Applicable and Not Quantifiable for Utility Ratemaking

Cost Category			Considerations
1	Social	Technology Synergies	As new technologies are interconnected to the grid, system impacts must be accounted for in order to determine their true integration costs, reliability impacts, or overall cost-effectiveness. Whether it may be intermittency with renewables, or increased transformer loads with electric vehicles, operational issues and increased costs can arise if not planned for appropriately. Technology adoption also creates the opportunity to leverage multiple technologies to gain synergistic value with paired deployments. Whether solar and energy storage, or electric vehicles and demand response, combining technologies can leverage the overall benefit/value to the customer and utility, while minimizing potential impacts. As common communication protocols are created, and interoperability standards are established, the ability to gain technological synergies will become greater.

Attachment A

Potential DG Value and Cost Categories

Not Applicable for Utility Ratemaking

Cost Category			Considerations
1	Avoided Cost/Financial Risk	Avoided Fuel Hedging Costs	Avoided fuel hedging costs are not a relevant factor to consider when assessing how much non-DG customers should be willing to pay DG customers for adopting solar because fuel costs for non-DG customers must continue to be hedged by the utility. Additional DG does not allow the utility to avoid hedging natural gas and power for non-DG customers' energy needs.
2	Avoided Cost/Financial Risk	Avoided Power Plant Decommissioning Costs	Avoided power plant decommissioning costs are zero. APS believes that the cost of decommissioning a combustion turbine, the likely avoidable power plant, will be offset or exceeded by its salvage value at the end of its life.
3	Avoided Cost/Financial Risk	Avoided Power Plant Capital Costs - Customer's Capital Contribution	The amount individual customers contribute towards their own DG system is irrelevant for purposes of calculating a value of DG which will be passed on to non-participating customers. For example, it does not matter whether a residential customer pays $500 or $500,000 for his or her system -- what matters is how much non-DG customers are required to ultimately pay for the system's production.
4	Security & Reliability	Grid Security	As designed for personnel and equipment safety, DG does not operate without power from the grid
5	Security & Reliability	Grid/Service Reliability	DG does not improve grid reliability and will lead to additional costs. With increasing penetrations of DG, investments must be made in both the generation and transmission/distribution areas to maintain reliability at current levels. Investments include flexible, fast ramping generation, voltage management, and distribution automation. Investments necessary are unique to each utility based on DG penetration and current system characteristics.
6	Environmental	Health Effects (Benefits)	The health effects of DG are difficult to quantify. "External" costs and benefits that are not recovered through (or have an impact on) retail electric rates should not be included in the assessment of DG benefits. The EPA takes health effects into account when determining emission control regulations and associated costs.
7	Environmental	Non-Compliance Environmental Effects	APS complies with environmental rules and regulations. . Any other environmental benefits are not recovered through rates and should not be considered in the assessment of solar benefits.

Potential DG Value and Cost Categories

Not Applicable for Utility Ratemaking

Cost Category			Considerations
8	Social	Economic Development and Jobs	Economic development and jobs creation are desirable outcomes from virtually any investment in generation resources, whether those resources are DG 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. The impacts from local economic development/job creation are not used in the setting of utility rates. 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 nonparticipating 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. None of the studies provided to-date offer such a comprehensive analysis.
9	Social	Civic Engagement/Conservation Awareness	No value should be assigned. Value for conservation awareness is already captured in the societal cost test for energy efficiency programs by way of the energy savings produced by participation in those programs.
10	Social	Energy Subsidies (incentives, rebates, tax credited, etc.)	APS does not believe that federal and state tax and spending energy subsidies are relevant to the issue of DG value and cost. These subsidies are federally mandated polices which impact all rate payers alike and do not result in cost shifting from one customer to another. Therefore this issue should not be included in the evaluation.

Attachment A

Potential DG Value and Cost Categories

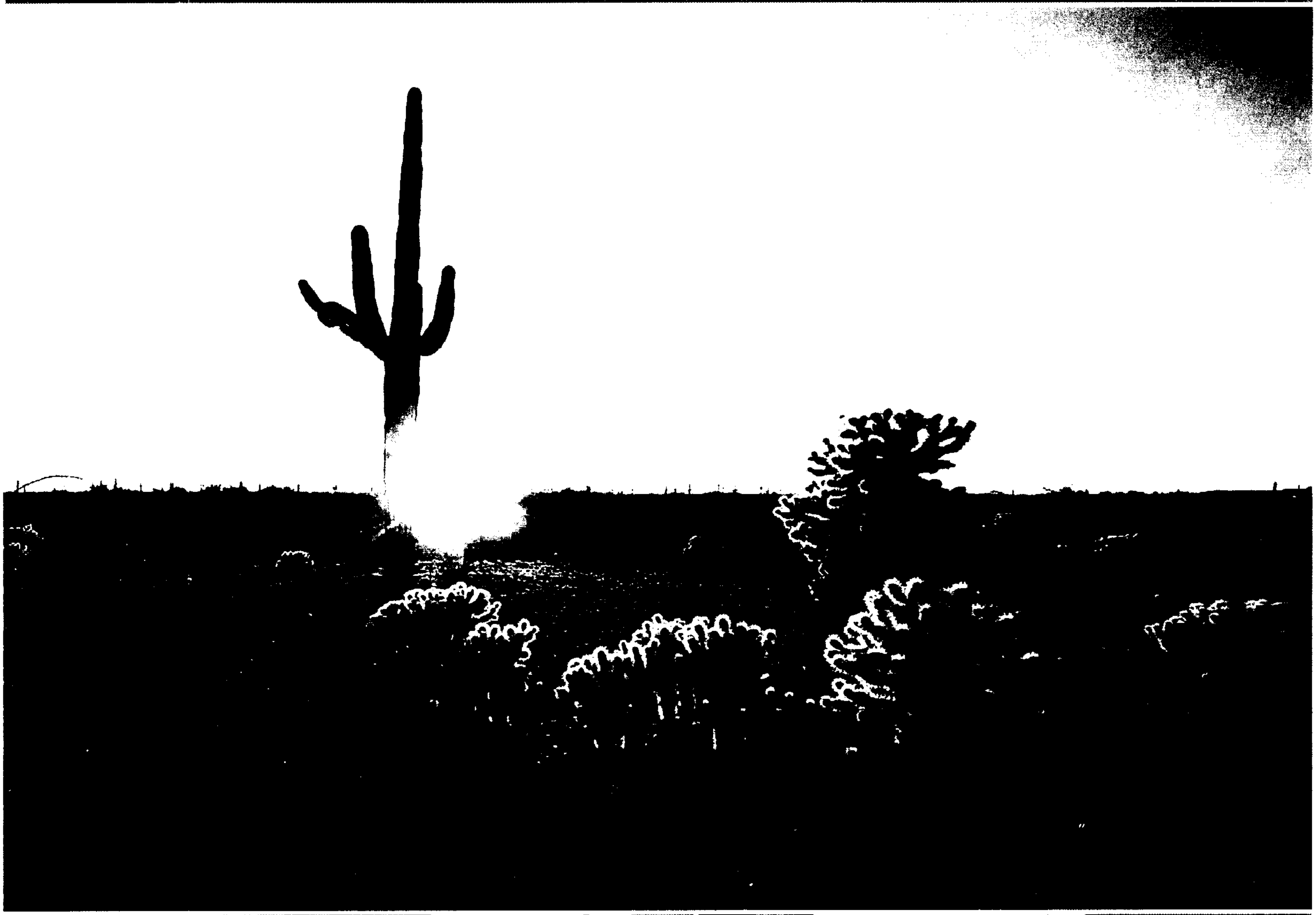
Not Applicable for Utility Ratemaking			
Cost Category			**Considerations**
11	Avoided Cost/Financial Risk	Avoided Market Price Mitigation	Price reductions for natural gas and/or wholesale power could be a relevant factor to consider, but assertions that reductions in demand will have meaningful impacts on prices seem dubious given the levels of demand reduction being contemplated. The correct methodology for assessing the impact of DG on natural gas and wholesale power markets would require that a comprehensive market study be performed to (1) quantify the potential impact on regional natural gas and wholesale power demand from expanding DG, and (2) estimate the price elasticity of supply which would intersect with the shift in the relevant demand curve. A study by Lawrence Berkeley National Lab4 (LBNL Study) and a report from the US Energy Information Administration both provide evidence that a tremendous amount of renewable energy would be required to have a noticeable impact on gas And power markets. The LBNL Study estimates the impact on natural gas prices from increased renewable generation displacing natural gas generation. 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 Report, 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.

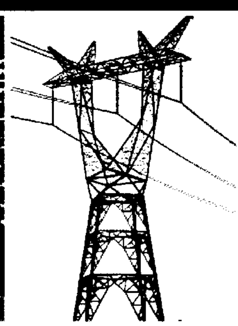
[4] Wiser, R., M. Bolinger and M. St. Clair. *Easing the Natural Gas Crisis: Reducing Natural Gas prices Through Increased Deployment of Renewable Energy and Energy Efficiency*, Lawrence Berkeley National Laboratory. January 2005.

Attachment B

PREPARED FOR: ARIZONA PUBLIC SERVICE

2013 Updated Solar PV Value Report





MAY 2013

SAIC®

2013 Updated Solar PV Value Report

Arizona Public Service

May 10, 2013

SAIC.

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Section 1
INTRODUCTION

In January 2009, Arizona Public Service Company (APS) commissioned a landmark study (formally titled the *Distributed Renewable Energy Operating Impacts and Valuation Study* and referred to herein as the 2009 Study) that developed sound methodologies and processes for determining the value of distributed solar energy to the utility. Prepared by a group of technical experts led by R. W. Beck, Inc. in collaboration with APS management and staff, the 2009 Study was guided by input obtained through a deliberative stakeholder engagement process. The 2009 Study began in 2008 and reviewed, analyzed, and vetted both conventional and non-conventional approaches to valuing selected distributed solar technologies within the APS service territory.

The 2009 Study assessed specific value components of the three primary functional areas of APS: distribution, transmission, and generation. The 2009 Study, an exhaustive examination unique to APS, was among the first in the industry to provide a detailed assessment of how selected distributed solar generation resources could impact specific functions of utility operations and can be valued by a utility.

Changes in power markets conditions and an increase in distributed solar installations at APS since the 2009 Study prompted APS to retain SAIC Energy, Environment and Infrastructure, LLC (SAIC) - the acquiring entity of R. W. Beck, Inc. - to prepare an update (referred to herein as the 2013 Updated Solar PV Value Report, or Report). This Report revises prior assumptions and analyses concerning the valuation of distributed solar resources resulting in updated valuation estimates for APS. Specifically, this Report provides an update of the valuation of future distributed solar photovoltaic (solar PV) systems on the APS service territory installed after 2012.

Distributed solar systems are typically small-scale solar based technologies installed at or near retail load (i.e., located on or near a customer's house or business). Utility scale solar projects are generally larger in size, designed to sell solar generated power at the wholesale level, and interconnect direct to the utility side of the meter at the transmission level. Utility scale solar projects were not included in the 2009 Study and are not considered in this Report.

The 2009 Study assessed the value of both fixed and single-axis tracking solar PV as well as the value of residential solar hot water systems and commercial day lighting applications (referred to collectively as solar distributed energy). The predominant solar distributed generation anticipated in the next few years is fixed solar PV; therefore, this Report is based on the potential value from fixed solar PV systems. It should be noted however, the energy production projections and associated energy offsets outlined herein for solar PV could be comprised of a blend of distributed solar energy technologies.

The 2009 Study utilized a marginal or incremental approach for valuation. The methods and analyses developed included a review of the potential impacts from future solar resources on the APS system for specific target years. Unless otherwise noted herein, the methods and processes developed for the 2009 Study, including the incremental approach, have been applied to the calculation of the solar PV value described in this Report.

2009 Study Findings

The 2009 Study developed a range of potential unitized savings associated with solar distributed resources derived from a detailed analytical review of APS's unique systems. Assumptions impacting this range included: the configuration of the existing and future state of the APS system; the quantities and types of installed solar distributed energy capacity; future utility scale generation investments; estimated demand (load) requirements; projections of costs and resources to provide power to APS customers; and the associated needs for capital improvements to APS's distribution, transmission, and generation systems.

The resulting benefits of solar resources outlined in the 2009 Study were presented as a range of quantitative values, expressed in both then-current dollars and future dollars for the selected years of review (2010, 2015, and 2025). This range of values was based on the potential installed capacity of solar resources, associated generation characteristics, and associated reductions to the energy and capacity needs of APS. Generation characteristic ranges were developed using bookends of hypothetical deployment scenarios capturing the high, low, and targeted scenarios.

As shown in Table 1-1, the 2009 Study presented a stacked range (maximum and minimum) of potential unit savings (in cents per kilowatt-hour (kWh)) for 2025 by value category from low, distribution capacity related savings to high, energy related savings. Although not reflective of any specific scenario analyzed for the 2009 Study, these results identify the relative potential for savings by value categories.

The 2013 Expected Penetration Case results are presented in Table 1-1 for comparison purposes and are further discussed throughout this Report and summarized in Section 3.

Table 1-1
2025 Solar PV Potential Value Range

Value Category	2009 Study Potential Value (cents/kWh) (1)	2013 Report Potential Value (cents/kWh) (2)
Distribution System	0 to 0.31	0
Transmission System	0 to 0.51	0.32
Generation System	0 to 1.85	1.66
Fixed O&M	0.81 to 3.22	0.29
Fuel, Purchased Power, Emissions & Gas Trans.	7.10 to 8.22	5.93
Total	**7.91 to 14.11**	**8.19**

(1) Ranges represented in 2009 Study are not reflective of a single scenario.
(2) Values from the Expected Penetration Case, see text. Numbers are rounded and may not add.

Summary of Updated Assumptions

APS system characteristics and market conditions have changed since the 2009 Study directly impacting the value associated with distributed solar PV based on Report assumptions including:

- The existing and projected costs for APS to produce and/or purchase power from the market have lowered dramatically since the 2009 Study, primarily as a result of lower natural gas prices used as a fuel source for electric generation. In 2008, natural gas prices were approximately $9.00 per million British Thermal Units (MMBtu); in 2012 natural gas prices were approximately $3.50 per MMBtu. Downward pressure on natural gas prices are the result of increased national supply due to: exploration; production, including widespread use of hydraulic fracturing; and improvements in natural gas recovery methods and technologies.

- Projections for carbon dioxide (CO_2) emission related costs have reduced significantly since the 2009 Study. In the 2009 Study, estimates for future CO_2 costs were approximately $50 per ton (in 2025), based on the consideration of future federal legislation under consideration at that time. The CO_2 reduction legislation was never passed, nor does it appear that such legislation will be introduced in the near future. However, APS has incorporated CO_2 emission related costs in its planning documents based on an analysis conducted by Charles River Associates, whereby costs are incurred beginning in 2019 and are assumed to escalate to a value of approximately $22.00 per ton in 2025.

- The number of installed distributed solar PV systems on the APS system has increased dramatically. In 2008, APS had under 1,000 solar PV systems installed in its service territory. As of 2012, this number had increased to over 14,000. According to APS, over 80 percent of the new solar PV systems in 2012 were installed under third-party solar leases. Third-party lease and financing options have driven higher market participation within APS's service territory than anticipated in the 2009 Study. Additionally, approximately 60 percent of customers with solar PV systems have opted into one of APS's time of use (TOU) retail rate tariffs. The projected values from solar PV developed in this Report reflect the incremental solar PV installations from the end of 2012 to the target years identified herein. This data was used as a baseline for this Report.

- APS reports that only a very small percentage of the solar PV systems installed in its service territory utilize single-axis tracking technologies. As a result, this Report focuses on the value of fixed solar PV as the expected incremental system to be installed in the future. In general, single-axis tracking technology could be expected to have slightly higher energy related value as a result of modestly higher hourly energy production, as well as slightly higher capacity related value, as a result of daily production that extends further into the evening hours, relative to fixed solar PV systems. The scenario analysis developed for this Report, as described herein, could reasonably be considered to include output from the relatively small number of existing and expected single-axis tracking systems installed in the APS service territory.
- APS's solar PV incentive programs, as approved by the Arizona Corporation Commission (ACC), have allowed the organic market growth for solar PV deployment to meet the requirements for solar generation on the system as a whole. An analysis of the locations of solar PV installations under this "market-based" approach have not resulted in significant localized penetration regions, but instead these installations have been geographically spread-out across the APS service territory. This Report assumes future deployment locations consistent with the observations of existing penetrations to date.
- Total load (demand and energy use) projections for APS customers are markedly lower than the forecasts utilized in the 2009 Study due to the economic recession and general economic slowdown across the country as well as the state of Arizona energy efficiency standards that have reduced both energy and demand projections. As a result, the projected need for capital improvement projects on the APS system in general has decreased.
- The 2009 Study considered the value of marginal avoided losses by comparing projected annual hourly system load profiles with and without solar resources to determine both annual energy and peak demand losses at the system level for each deployment scenario. However, this approach was theoretical in nature and it has not been technically feasible to verify the accuracy of the estimate based on marginal losses. Accordingly, this Report utilizes known system average energy and demand losses observed and measured by APS in its approach to value the avoided losses as a result of the increased solar PV projections.

The impact of these key assumption changes and their incorporation into the value calculations for solar PV generation are discussed herein.

Summary of Methodology

Unless otherwise noted, and to the extent possible, the 2013 Updated Solar PV Value Report utilizes the 2009 Study methodology for assigning incremental value to future solar PV deployments throughout the APS service territory. Description of these methodologies is detailed in Section 2 of this Report. These methodologies were applied to the following three functional areas of the utility, which are also referred to as value categories for this Report:

- Distribution;
- Transmission; and
- Generation (Energy and Capacity).

This Report provides an estimate of the incremental value of future solar PV for the APS system for 2015, 2020, and 2025, which are the target years identified for the analysis conducted herein. Values are stated in current-year dollars (2013) for these periods, as well as in nominal dollars. The hypothetical bookends developed for the 2009 Study were theoretical scenarios that were meant to explore the opportunity for value associated with a range of various types and configurations (including location) of distributed solar systems. This Report focuses on realistic expectations for growth of solar PV in the APS service territory based on the penetration to date of specific applications of solar PV systems and updates the value categories identified in the 2009 Study.

Other Sources of Information

Since the 2009 Study, APS has investigated the costs and performance characteristics of solar PV installed on its system. Sources developed or reviewed by APS include:

- the 2012 Integrated Resource Plan (2012 IRP), dated April 2012;
- the APS 2013-2022 Ten-Year Transmission System Plan (Ten-Year Plan); and
- the *"Solar Photovoltaic (PV) Integration Cost Study"*, prepared by Black and Veatch, dated November 2012, on behalf of APS, that reviewed the costs associated with integrating significant numbers of solar PV systems on a year-round basis on the APS system.

The 2009 Study did not include a valuation of solar PV integration costs because little information regarding these costs was available at that time, therefore this Report does not include a value for potential integration costs that APS will likely incur. The *"Solar Photovoltaic (PV) Integration Cost Study"* represents the most current review available for potential integration costs APS could expect as solar PV deployment increases over time.

SAIC relied upon information provided by APS as well as information concluded in these supplemental reports for this Report. SAIC reviewed all the data provided by APS for this Report for reasonableness.

Description of this Report

This Report is presented in three sections. Section 1 describes the objectives of the 2013 Updated Solar PV Value Report, summarizes key assumptions, and provides an overview of the foundational elements of the 2009 Study. Section 2 presents the methodologies used in the analysis of the projected solar PV systems and underlying support for the updated solar PV value assessment which is summarized in Section 3.

Section 2
METHODOLOGY

This section provides a description of the solar characterization, dependable capacity, and other methodologies utilized for this Report.

Solar Characterization

Solar characterization refers to the characteristics of the existing and projected solar PV technologies deployed in the APS service territory and their associated energy production. This section reviews the solar characterization utilized in the 2009 Study and compares underlying assumptions that have been updated for this Report.

Solar PV Modeling for 2009 Study

The 2009 Study utilized the Solar Analysis Model 2.0 (SAM 2.0) developed by the National Renewable Energy Laboratory (NREL) for solar PV system modeling. The SAM 2.0 model produced hourly production simulations based on typical meteorological year (TMY) weather data and included allowances for loss factors and performance characteristics for commercially available solar PV inverters. The model was calibrated by adjusting input variables to produce output projections that were consistent with empirical PV system data as observed by APS in the field. For the 2009 Study, TMY data was obtained from Clean Power Research for selected site-specific areas in the APS service territory.

Solar PV system performance is measured in kWh per direct current kilowatts (kW_{DC}), reflecting the amount of alternating current (AC) kWh produced per installed direct current (DC) kilowatt (kW) per year. As indicated in the 2009 Study, changes in orientation, between the southwest and southeast, and tilt of the solar PV systems, between 15 and 33 degrees, resulted in differences in total annual performance metrics resulting in a range of annual electric production from approximately 1,600 to 1,700 kWh/kW_{DC}.

Based on empirical testing results and the professional experience of the 2009 Study team, a baseline system for residential application was defined as a south-facing array at a typical roof pitch of an 18.4 degree tilt that generated an annual performance of approximately 1,600 kWh/kW_{DC}. For commercial systems, the baseline assumptions resulted in an estimated annual production of approximately 1,541 kWh/kW_{DC} for flat plate arrays at a 10 degree tilt located on flat structures with minimal investments in supporting structures.

Solar PV Modeling for 2013 Report

The assumptions used in this Report are based on actual solar PV systems installed on the APS system and associated production characteristics, rather than production modeling assumptions utilized for the 2009 Study. APS indicated that it utilized an industry standard modeling software (PVWatts) using a 30-year TMY to represent a typical, standardized solar production profile for solar PV systems within its service territory. Current APS solar production assumptions are 1,650 kWh/kW$_{DC}$ for residential applications, based on a sample of installed solar PV systems in its service territory, and 1,500 kWh/kW$_{DC}$, for non-residential (commercial) applications. By the end of 2014, APS intends to deploy production meters on all distributed solar systems that have received an incentive payment. Data obtained from distributed solar PV production meters could result in a change in production assumptions over time.

Solar Characterization Conclusions

The values developed by APS for characterization of solar PV systems fall within the range developed during the modeling efforts for the 2009 Study. Therefore, annual performance metrics of 1,650 kWh/kW$_{DC}$ and 1,500 kWh/kW$_{DC}$, were used for the projected residential and commercial systems, respectively, throughout this Report.

Deployment Assumptions

2009 Study

The 2009 Study developed solar PV deployment projections based on assumptions concerning payback periods, incentive payments, costs of associated materials (PV arrays, etc.), projected increases in average system rates (retail rates), total technical potential (based on total rooftop estimates), and other demographic data for residential and commercial applications within the APS service territory. These assumptions were utilized as input values to a Bass diffusion model to simulate expected uptake by retail customers for solar PV systems over the study period. This methodology was utilized to determine the relative numbers of residential and commercial solar PV systems expected to be installed under the various deployment scenarios considered for the 2009 Study.

2013 Report

This Report utilizes updated distributed solar PV deployment projections developed by APS and disaggregated by residential and commercial systems. The number of deployed residential solar PV systems included in the existing base increased from under 1,000 to approximately 14,000 between 2008 and the end of 2012 and the average size (capacity) of these systems has increased from approximately 5.6 kW$_{DC}$ in 2008 to approximately 7 kW$_{DC}$ in 2013. Installed distributed solar PV commercial systems increased from 38 with an average capacity of approximately 105 kW$_{DC}$ in 2008 to approximately 700 as of year-end 2012 with an average capacity of 349 kW$_{DC}$ for large commercial systems and 74 kW$_{DC}$ for small commercial systems.

The projections for future solar PV deployment in this Report are based on APS data from installed solar PV systems as of the end of 2012 whereas the 2009 Study used 2008 as a starting point.

As of 2012, approximately 26 single-axis tracking system solar PV systems have been installed in APS's service territory. The number of installed single-axis systems is relatively small compared to flat plate systems installed to date. However, as previously noted, the production assumptions included in the scenario analysis described below could reasonably be considered to include output from single-axis tracking systems.

Deployment Projections

APS Renewable Energy Standards Goals

The state of Arizona is one of many states that has a mandated Renewable Portfolio Standard, referred to in Arizona as its Renewable Energy Standards (RES). The RES promulgates regulatory policies requiring electric utilities, such as APS, to increase the production of electricity from renewable energy sources including wind, solar, biomass, and geothermal resources.

APS's forecast for energy requirements from distributed systems is based on the RES percentage of total electric sales for each year and assumes the requirement that 30 percent of the total renewable energy must be procured from distributed resources. Each of the solar PV penetration scenarios reviewed for this Report (described below) meets APS RES mandates by 2025.

2009 Study Deployment Scenarios

The 2009 Study defined three penetration cases (or deployment scenarios) based on the market simulation modeling effort described above. A payback calculation and consideration of economic factors were used to determine how customers would adopt certain solar technologies over time.

The deployment scenarios included in the 2009 Study included a Low, Medium, and High Penetration Case. Assumptions that varied between cases included: capital costs for deployment, federal tax credits and incentives, and expected retail rate projections, among others.

The 2009 Study also included a targeted deployment scenario whereas APS would provide incentives to install solar resources in targeted locations to postpone upgrades. Targeted deployment was assessed as a consideration to gauge the potential to reduce peak demand on specific equipment in the distribution system, averting additional infrastructure investments were this deployment scenario to occur. The targeted scenario used the same assumptions as the High Penetration Case in combination with targeted incentives.

2013 Report Deployment Scenarios

The 2013 Report projections are based on three potential deployment scenarios and estimated production outputs to explore the relationship between solar PV penetration and value to APS. The following scenarios were provided by APS:

Expected Penetration: The Expected Penetration Case represents APS's best estimates for penetration for solar PV and associated energy projections based on current and observed market factors, near-term programmatic expectations through 2015, and actual customer installations to date, in addition to state-mandated goals for distributed solar by 2025. The Expected Penetration Case results in approximately twice the amount of solar PV necessary to meet APS's RES distributed energy requirements by 2025.

It should be noted that while the Expected Penetration Case represents APS's best estimates for solar PV adoption, it does result in greater solar PV than required for compliance with RES distributed energy requirements in 2025. As such, it does not represent APS's corporate view of how much distributed energy will be installed over the long run. It is a "test case" prepared for this Report to determine potential value to APS from solar PV if such deployment projections were to occur.

High Penetration: The High Penetration Scenario was developed by APS to reflect a reasonable upper bound for solar PV adoption that could include factors such as lower solar PV system costs, higher retail rates, and changed customer behaviors that encourage system development. The High Penetration Scenario includes a significant increase in commercial solar PV development in the long-run. Although not reflective of APS's current expectations for future growth of solar PV, this scenario provides a reasonable high-end projection for purposes of this Report. The High Penetration Scenario results in approximately 3.5 times the amount of solar PV necessary to meet APS's RES distributed energy requirements 2025, and would be approximately equivalent to APS fulfilling its entire RES obligation from distributed energy resources alone.

Low Penetration: The Low Penetration Scenario reflects the incremental distributed energy growth projected in APS's 2012 IRP, as developed in 2011. Forecasted growth from the 2012 IRP approximately reflects full compliance with APS's RES distributed energy requirements by 2025. This scenario is not reflective of APS's expectations for future growth of solar PV, but provides a reasonable lower bound for purposes of this Report.

The annual solar PV energy projections incremental to the installed solar PV on the system as of the end of 2012 for each scenario, developed by APS and used as a basis for the analysis in this Report, are presented in Table 2-1.

Table 2-1
Incremental Solar PV Energy Adoption Projections (1)

	Incremental Solar PV Energy w/ Losses (MWh) (2)		
Case/ Scenario	2015	2020	2025
Expected Penetration Case	430,554	1,397,175	2,741,866
High Penetration Scenario	430,554	1,782,433	5,403,473
Low Penetration Scenario	290,132	601,226	1,302,165

(1) Projections are incremental to the installed solar PV on the system as of the end of 2012. Projections include 7 percent losses, see text and Table 2-3.
(2) Megawatt-hour (MWh)

2012 Installed and 2013 Projected Solar PV Capacity

By the end of 2012, APS had approximately 222 megawatts AC (MW_{AC}) of total nameplate installed distributed solar PV on its system, inclusive of both residential and commercial applications[1]. In 2013, APS anticipates a significant increase in projected installations which would result in approximately 296 MW_{AC} of cumulative installed nameplate distributed solar PV.

The large increase in predictions for 2013 is due to concrete distributed energy programmatic activity by APS retail customers. Beginning in 2013, APS had existing solar PV reservations and incentive funding which could provide over 50 MW of residential capacity and over 50 MW of commercial capacity.

The solar PV capacity projections identified above are nameplate solar PV capacities and are not dependable capacity values. Dependable capacity values are discussed later in this Report.

Dependable Capacity

A critical aspect of the 2009 Study was the determination of the dependable capacity available from solar PV, which is the ability of solar PV to reliably serve APS's total system load during peak periods. The dependable capacity analysis was used to determine the amount of solar PV capacity required to provide the same level of reliability as traditional generation resources. This Report utilizes the methodology for calculating the dependable capacity that was developed for the 2009 Study. Dependable capacity calculations were developed separately for the generation, transmission and distribution systems.

This Report (and the 2009 Study) determines capacity value from solar PV installations by their relative contribution to peak load. For generation and transmission systems, the peak load is determined at the system level (system peak) because the installed generation and major transmission lines must be designed to serve the system load requirements at that time. The system peak is the one hour of the year for which the customers' load is the highest. In addition, the generation analysis includes changes to Effective Load Carrying Capacity (ELCC), which includes loss of load simulations, which are a measure of reliability used to calculate dependable capacity values for generation.

The distribution and sub-transmission systems are designed to meet the localized needs of particular feeders or substations. This feeder peak may or may not be coincident with the system peak; and is driven by the usage of the customers that are served by those feeders. If the load is primarily residential, the peak is expected to be rather late in the day, when customers return home and begin to increase their

[1] This value reflects a preliminary projection of 2012 year end installed distributed solar PV capacity.

electricity usage. Alternatively, if the load is primarily commercial, the peak may be earlier in the day, when customers are at work.

Solar PV systems also have their own peak; the hour in which they generate the maximum amount of electricity. Assuming flat panel type of solar PV systems, as identified in this Report, the production peak is generally at 1:00 p.m., when the sun is at its highest point and is producing the most irradiance. Production decreases rapidly throughout the afternoon until it is totally diminished in the evening. It is the relationship between the production of the solar PV systems at the time of the load peak of either the system (for generation and transmission) or the feeder peaks (for distribution and sub-transmission) that results in the calculation of dependable capacity.

Dependable Capacity – Generation / Transmission

Deferring generation and transmission investment affects the planning, design, and operation of the transmission system which is highly regulated by North American Reliability Corporation (NERC) Reliability Standards. The reliability criteria are deterministic and are based on allowable system performance following contingencies. For the grid-level transmission system (i.e. higher than 69-kilovolt (kV)), specific projects that are related to planned generation resources that could potentially be postponed or eliminated with the future solar PV penetration scenarios were evaluated with those specific generation resources.

Therefore, the methodology for determining the ability to defer generation and related transmission investments requires determining the dependable capacity of the solar distributed generation and thus the dependable load reduction and the resulting impact on reliability. The 2009 Study used an industry-accepted methodology to measure the reliability of meeting the APS system load with a given portfolio of resources. The approach was based on a statistical analyses to determine the level of solar output that would be sufficient to allow a generation deferral without impacting system reliability.

To evaluate the dependable capacity of solar resources, APS performed a series ELCC simulations, which is a measure of reliability used to calculate dependable capacity values for generation. The ELCC simulations modeled the APS existing portfolio after adding 100 MW_{AC} of solar PV nameplate capacity to determine its dependable capacity, as described in the 2009 Study. Because the ELCC measurement can vary significantly depending on the underlying load shape, the ELCC computations were performed for five historical annual hourly load profiles: 2003 through 2007.

For this Report, the solar PV dependable capacity was calculated using the same ELCC results used in the 2009 Study. Table 2-2 outlines the solar PV capacity value percentages used to arrive at the associated dependable capacity projections for 2015, 2020, and 2025.

Table 2-2
Solar PV Dependable Capacity – Generation

Scenario	2015	2020	2025
Expected Penetration Case			
Nameplate PV Capacity (MW_{AC}) w/ losses	242	768	1,504
Avg. PV Capacity Value	45.9%	30.5%	21.0%
Incremental Dependable Capacity (MW)	111	235	316
Incremental Capacity Value of the Next 50 MW	34.1%	11.4%	5.3%
High Penetration Scenario			
Nameplate PV Capacity (MW_{AC}) w/ losses	242	971	3,044
Avg. PV Capacity Value	45.9%	26.4%	12.4%
Incremental Dependable Capacity (MW)	111	256	376
Incremental Capacity Value of the Next 50 MW	34.1%	6.4%	3.0%
Low Penetration Scenario			
Nameplate PV Capacity (MW_{AC}) w/ losses	166	338	734
Avg. PV Capacity Value	48.4%	43.7%	33.3%
Incremental Dependable Capacity (MW)	80	148	244
Incremental Capacity Value of the Next 50 MW	41.9%	29.6%	17.4%

Note: Incremental Nameplate Solar PV Capacity includes 11.7 percent peak hour demand loss

It was determined in the 2009 Study that significant implementations of solar PV can result in a shift in the APS system peak to a later hour when solar PV resources are less productive. With no incremental solar PV, the APS system is projected to peak in the 17:00 hour. Because the output of the solar distributed resources becomes significantly less as the available sunlight diminishes at dusk, the delay of the peak hour to a later hour diminishes the ability of the solar distributed resources to meet the electric system peak demand and satisfy reliability planning criteria. Table 2-2 clearly indicates that as the peak shifts and solar resources become less productive, the incremental capacity values are reduced somewhat exponentially (as shown for each scenario under Incremental Capacity Value of the Next 50 MW).

Dependable Capacity – Major Transmission Projects

As discussed in the 2009 Study, potential deferral of transmission investment is due to the reduction in effective load growth as a result of locating the solar PV at the load, delaying the time at which the system would reach its peak load. The 2009 Study concluded that solar resources were not projected to have a significant impact until the end of the then current ten-year transmission plan. Since specific project data was not available beyond that time, simplifying assumptions were utilized to determine what types of investments might be necessary on APS's transmission system beyond that period.

For this Report, the Ten-Year Plan includes proposed major transmission projects up to the end of the study period (2025) when significant solar penetration is anticipated in the Expected Penetration Case and High Penetration Scenario. Therefore, the potential for delaying specific transmission projects based on specific load levels has been analyzed by these solar PV penetration scenarios.

SAIC reviewed information provided by APS for forecasted capital investments to identify the major planned transmission projects corresponding to system growth needs that could potentially be deferred. For the target years, SAIC conducted a comparison of the APS projected hourly loads both with, and without, solar PV installed to estimate revised system peaks for the target years at expected and high penetration levels. The difference between the revised system peaks and the reference case peak loads without solar PV determined the dependable capacity for transmission deferrals. The revised peaks were compared to the proposed transmission project load levels to determine if the associated project costs and timing could be delayed past the target years of this Report.

Dependable Capacity –Sub-Transmission and Distribution

For the 2009 Study, hourly normalized solar distributed energy data was also used to calculate dependable capacity at the time of the individual feeder peak loads for sample feeders on the distribution system[2]. An average cost of distribution improvements per MW of non-coincident load growth was used to calculate the value to the distribution system and was applied under a hypothetical scenario, assuming solar installations would be targeted in high concentrations along the required feeders or near substations.

As indicated previously, APS is experiencing an organic and non-selective market based growth of solar PV systems that has resulted in a geographically diverse (i.e. non-concentrated) penetration pattern that does not coincide with the 2009 Study targeted scenario. Based on the existing locations of existing solar PV systems within the APS service territory, an evaluation was conducted to determine if sufficient solar PV has been installed on existing distribution feeders to defer planned upgrades. This methodology was then applied to projected solar PV forecasts spread across all feeders to determine the number of feeders for which potential upgrades could be deferred due to the reduced peak load.

For the 69-kV sub-transmission system, APS identified specific load-growth based planned projects that could potentially be postponed by the future solar PV penetration scenarios. The projected solar PV penetration at the feeder level was totaled to

[2] In the 2009 Study the hourly energy data was obtained using SAM 2.0 developed by NREL, using TMY production data.

determine the regional impact to evaluate whether any of the planned projects could be deferred for each region.

Reduction in System Losses

Electricity generated at the site of application, such as a distributed solar PV system, reduces the load required to be served by a centralized power generating facility and thus reduces the electricity line losses that occur during delivery of electricity to the load. In addition to line (energy) losses, there are demand losses that occur at the time of a peak load. Reductions in peak demand losses reduce system capacity requirements.

Since demand varies on an hourly basis, and solar output varies on an hourly basis (both relatively significantly, but independent of each other) a theoretical hourly analysis of loss savings was conducted for the 2009 Study. Projected annual hourly system load profiles, with and without solar, were compared to determine annual marginal energy losses, as well as marginal peak demand losses at the system level.

This approach was theoretical to determine the impact of avoided losses for the 2009 Study but the results of such an approach cannot be verified. Therefore, this Report utilizes a seven percent average energy loss and an 11.7 percent system peak demand loss as recorded by APS.

Table 2-3 provides an estimate of the annual system wide energy loss savings in the target years for each of the deployment cases. This table also includes the incremental solar PV resulting from the deployment under the scenarios reviewed for this Report. The combination of the incremental deployed energy and the loss savings is equal to the total energy savings associated with each solar PV penetration scenario (presented in Table 2-1 above).

Table 2-3
Potential Transmission & Distribution System Energy Loss Savings

	Incremental Solar PV Deployed (MWh)	Annual Energy Losses (MWh)	Incremental Solar PV Deployed (w/ Losses) (MWh)
Expected Penetration Case			
2015	402,387	28,167	430,554
2020	1,305,771	91,404	1,397,175
2025	2,562,491	179,374	2,741,866
High Penetration Scenario			
2015	402,387	28,167	430,554
2020	1,665,825	116,608	1,782,433
2025	5,049,975	353,498	5,403,473
Low Penetration Scenario			
2015	271,151	18,981	290,132
2020	561,894	39,333	601,226
2025	1,216,976	85,188	1,302,165

Note: Energy losses are based on 7 percent system average, see text.. Numbers are rounded.

Value Assessment Methodology

This section provides a review of the valuation methodology applied to each of the functional areas of the utility; distribution, transmission, and generation. The calculated value assessments are presented in Section 3 of this Report.

Distribution System

The 2009 Report assessed the potential contribution from solar PV to the APS distribution system in four distinct areas including: reduced line losses (energy and peak demand), reduced capacity and associated deferment of capital expenditures, extended service life for distribution equipment, and reduced capital investments associated with proper equipment sizing upon initial installation.

To draw such conclusions, specific distribution feeders, substations, and associated equipment were analyzed to develop proper value estimates. In addition, distribution system components were modeled using APS's distribution software and Electric Power Research Institute's (EPRI's) feeder modeling tool (referred to as the DSS Distribution Feeder Model) to assist in the quantitative benefit analysis.

Because the distribution system as a whole has not changed dramatically since the 2009 Study, many of the same assumptions are still valid and were confirmed with APS for use in this Report. Where new analyses and/or assumptions were required, the methodologies are described.

System loss reductions (which apply to the distribution and transmission systems) are discussed above. The sections below discuss the three remaining values identified for the distribution system.

Deferment in Distribution Capital Expenditures

The 2009 Study analyzed the potential for solar PV to provide value to APS by decreasing distribution system capacity requirements due to the contribution of installed distributed solar PV systems. To the extent that solar PV systems reduce feeder peak demand, they can potentially decrease capacity required to serve load and defer capital improvements at the feeder and substation level. The 2009 Study concluded distribution capacity is solely based on local peak loads and therefore distribution capacity savings can only be realized if distributed solar systems are installed at adequate penetration levels and located on specific feeders to relieve congestion or delay specific projects. The 2009 Study also concluded that solar PV can only be used to defer upgrade projects for feeders with projected peak loads between the planning (90 percent) and emergency (100 percent) ratings (i.e. those for which peak demand is between these two rating criteria).

For this Report, existing solar PV installations were evaluated at the feeder level to determine if the market-based deployment has resulted in adequate penetration on a sufficient number of specific feeders to result in measurable savings.

2013 Feeder Screening Analysis

SAIC performed a screening level analysis across the APS distribution feeders where distributed solar PV has been installed to date. This analysis included a review of the following feeder information:

- Source substations and regional locations
- Feeder maximum rated capacity
- Customer types (residential or commercial) by feeder
- Solar PV capacity installed per feeder (residential, commercial)
- Feeder peak load (kW) and time and day of feeder peak
- Feeder peak load and system-wide solar PV installation growth rates
- APS's proposed substation and feeder capacity additions

To estimate the value of solar PV on the distribution system, APS feeders that had at least 10 percent or more of installed PV capacity relative to the total peak load on the feeder were analyzed. Out of a total of 1,351 feeders on the system, APS identified 872 feeders which had solar PV systems installed as of the end of 2012. Of these 872 feeders, 63 feeders were identified that met this initial screening criteria.

For each of these feeders, analysis was performed to estimate the contribution of solar PV to the peak load. Most of the feeders reviewed were residential feeders that typically peak close to sunset, when solar production is greatly reduced. As a result, the value of solar PV contribution for reducing distribution infrastructure expenses is minimal.

The analysis utilized a typical hourly solar PV production profile for feeder peak days (provided by APS) using output from the PVWatts modeling and based on characteristics from actual solar PV systems installed in APS's Flagstaff Community Power Project. This production profile was scaled to determine the total annual solar PV production on a feeder during the hour in which the feeder peaked, enabling analysis of each feeder's peak solar PV production relative to the peak load and rated feeder capacity. The residential production profile was used as a first level proxy for solar PV generation on a feeder because the higher annual production assumption (1,650 kWh/kW_{DC}) would indicate whether further screening was warranted (i.e. determining a mix of residential and commercial applications by feeder).

A comparison of each feeder's peak load relative to the rated feeder capacity, with and without solar PV, indicated those feeders where the installation of solar PV was potentially delaying the need for capital improvements by reducing load from greater than 90 percent of capacity to less than 90 percent. If loading was above 100 percent (of rated capacity) without solar PV, the upgrade project identified by APS could not be deferred by the existence of solar PV.

There were five feeders, out of a total of 1,351 that had a peak solar PV production that reduced load from above 90 percent of the feeder's rated capacity to below 90 percent, using the initial production screening assumption that all distribution penetration was from residential applications. Based on the expected feeder load growth, upgrades on these five feeders could be delayed from five to ten years.

SAIC also investigated the potential for impacts to feeder upgrades under the future solar PV penetration scenarios. It was assumed that future solar PV systems would be installed at the same growth rate for each feeder on the APS system territory. This is consistent with APS's existing approach of allowing the market to determine locations of future solar PV installations, as previously discussed. In this analysis, APS provided estimated growth for load by feeder, which was assumed to continue at a constant rate for the period reviewed, consistent with APS's modest overall load growth forecasts used in this Report.

The projected load with, and without, projected solar PV was compared to the feeder capacities to determine if upgrades could be postponed beyond the target years. The results of this analysis indicated that a total of nine feeders out of 1,351 could potentially reduce future load to below 90 percent of the feeder's rated capacity for 2025 under the High Penetration Scenario.

The conclusion from these analyses, and the very low capital expenditure required for feeder upgrades, is that there are an insufficient number of feeders that can defer capacity upgrades based on non-targeted solar PV installations to determine measurable capacity savings. This analysis supports the methodology and conclusions from the 2009 Study that found that no capacity savings existed from solar resources on the distribution system without specifically targeting the locations of solar resource installations on the distribution system.

Extension in Service Life

It was theorized in the 2009 Study that distributed solar systems may reduce capital investment requirements for distribution systems by reducing the loading on the equipment to extend equipment life.

If sufficient solar generation is coincident during peak demand hours on heavily loaded transformers, the solar generation could potentially prevent that overload condition. However, like most utilities APS historically has not maintained the hourly data on the quantity and frequency of overload occurrences and durations of individual distribution transformers. Consequently, the value associated with extension of service life could not be quantified for the purposes of the 2009 Study and was not available for updating for this Report.

Reduction in Equipment Sizing

As indicated in the 2009 Study, distributed solar resources may reduce capital investment by reducing loading on the equipment enough that size requirements can be decreased. Distribution system equipment is sized to serve the anticipated annual peak load, and is typically sized to anticipate growth in the peak load over time.

The cost to install, maintain, repair, upgrade, and replace equipment is affected by its size. As a result, solar PV installations that can reduce the annual peak load sufficiently to reduce the required equipment size can potentially provide value to the distribution system. However, this would require that the life of the solar PV systems be similar to the life of the equipment proposed. If the solar PV systems were removed or terminated early, for example, the utility would need to resize the remaining equipment at a considerable expense.

Additionally, as with many utilities, APS indicates that it maintains a lean inventory of standard sized conductor, transformers and other distribution related equipment to reduce its costs. Localized impacts from solar PV would need to be significant to justify changes between these standard sizes of equipment. Further, changing from a standard equipment sizing approach to an individualized approach could potentially eliminate supply chain purchasing economies of scale and result in added costs associated with reduced equipment sizes. Therefore, APS does not reduce equipment size requirements based on solar PV installations.

System Performance Issues

Though solar PV can potentially provide benefits to utilities including those discussed above, the increased penetration of solar PV installations by residential and commercial customers could also undermine the reliability, safety, and quality of power supply on the electric grid for utilities that do not plan for it, particularly during shoulder periods when loads are at their lowest and solar production is at its highest. High costs to provide reactive power/voltage support, additional interconnection requirements, and grid instability caused by anti-islanding requirements have been noted by several utilities. Automation to manage these issues can be costly, including switched capacitors (for reactive power requirements), active power management (where the power factor of solar PV systems output remains fixed or varies on a pre-determined basis), automatic reactive power requirements (where solar PV systems are required to automatically provide real-time dynamic reactive power support to the grid); and the continuous, active management of each solar PV system.

The Solar Integration Study conducted by Black and Veatch suggested that in the near term there are minimal costs associated with integrating these distributed resources. APS expects that increased operations and maintenance (O&M) costs will be realized with additional solar PV installed on its system and may further investigate these impacts as additional systems come online. The value of these increased costs have not been addressed specifically in this Report.

Summary of Updated Distribution System Findings

As indicated in the 2009 Study, the solar PV has limited impact on the summer peak demands that drive distribution infrastructure installations and upgrades, due to the non-coincidence of peak solar generation and peak customer, feeder, substation, and system loads. Increased penetration or sizes of solar PV also have limited effect on annual peak load reduction. The value ascribed to the APS distribution system from solar PV in the 2009 Study was limited to the potential reduction in capital expenditures in the targeted and single-axis sensitivity cases, due to the direct placement of resources on the specific feeders (targeted) and the higher production of single axis systems later in the day (i.e. solar generation that extends into the APS system peak hours). The analysis performed for this Report supports that conclusion; therefore, the only significant distribution system value from solar PV is the change in potential line losses, reflecting energy and peak demand savings which are calculated at the system level for this Report.

Transmission and Sub-Transmission

The 2009 Study determined that locating distributed solar generation near the demand (load source) benefits the transmission system primarily in two ways: 1) it reduces the line losses across the transmission system, as mentioned above for the distribution system and 2) it reduces the burden on the transmission system during peak demands, possibly allowing deferral of transmission investments, depending on the level of deployment.

The 2009 Study also noted that the intermittent nature of solar generation may adversely impact transient stability and spinning reserve requirements of the transmission system. This includes potential detrimental impacts of multiple solar PV inverter systems dropping off-line simultaneously, thus impacting transient stability limits. While this potential impact is still a concern, it was not analyzed or valued as part of this Report.

Potential Deferral of Sub-Transmission Investment

For the 69-kV sub-transmission system, APS identified specific load-growth related planned projects, represented in Table 2-4, that could potentially be postponed by the future solar PV penetration scenarios. The dependable capacity calculations indicate that by 2025 adequate distributed solar PV may exist in the Expected Penetration

Case, but these projects also must be evaluated by the contribution of solar PV to the feeder peak loads in the applicable region.

Table 2-4
69 kV Transmission Capital Improvement Potential Capex Deferral

Project Code	Region	Dependable MW Required for Deferral	In Service Date	Capex Investments (2013 $000)	Deferral Period
Project A	Metro Central	30 MW	2021	$14,065	3 Years
Project B	Rural Western	20 MW	2019	$7,980	3 Years
Project C	Metro Western	15 MW	2017	$560	3 Years
Project D	Metro Western	20 MW	2017	$1,600	3 Years
Project E	Northwest	10 MW	2021	$1,200	5 Years
Project F	Northwest	20 MW	2021	$3,200	5 Years
Project G	Northwest	20 MW	2017	$900	5 Years

Note: Capex investment represents total project cost, not annual savings value.

Evaluation of the feeders in each region indicated that the Rural Western region is not projected to have sufficient solar PV penetration based on an average feeder allocation to defer the proposed project beyond 2020 in the Expected Penetration Case. However, this region is projected to have sufficient incremental solar PV capacity by 2025 to defer a 20 MW project in the High Penetration Scenario.

The Northwest region is expected to have sufficient incremental solar PV installations by 2020 in both the Expected Penetration Case and the High Penetration Scenario to postpone a 10 MW project, as well as have sufficient incremental solar capacity by 2025 to postpone a 20 MW project. The projects in the Metro Central and Metro Western regions could not be postponed past the target years.

Potential Deferral of Transmission Investment

Upgrades to the grid-level transmission system (i.e. higher than 69-kV) include specific projects that are related to system growth as well as related to planned generation resources that could potentially be postponed or eliminated with future solar PV penetration scenarios. In the 2009 Study, APS analyzed the deferral of wholesale transmission investments using the dependable capacity of solar resources during annual peak load and assumed a generic 500 MW transmission upgrade based on projected scheduling rights. This was because at the time of the 2009 Study, solar distributed resources were projected to not have a significant impact until the end of the then current ten-year plan.

However, for this Report, actual planned transmission projects and projected APS loads were analyzed to determine potential deferrals. Major planned transmission projects in the APS Ten -Year Plan were evaluated based on the projected system peak load for the year the project is planned compared to the hourly load projections with and without solar PV for the target years. If the projected system loads (with solar PV) reduced the system peak load to less than the projected load for the target year in which a transmission project is planned, it is likely APS could postpone that project beyond the target year.

The hourly analysis utilized the PROMOD hourly load projections without solar PV as a reference case (a discussion of PROMOD is provided in the Generation section of this Report). An annual hourly solar PV production profile (the same PVWatts generated profile utilized in the distribution analysis) was scaled to the projected penetration levels to determine the projected solar PV on the system in each hour of the target years and subsequently the new hourly load projections with solar PV on the system. The new hourly solar PV loads were determined by subtracting the amount of solar PV produced in each hour from the reference case hourly load projections. The new system peak (with solar PV) was determined by taking the maximum hourly load for each of the target years for both the Expected Penetration Case and the High Penetration Scenario. The difference between the new system peak and the reference case peak is assumed to be the dependable capacity for deferral of transmission projects provided by the solar PV.

This analysis indicated that the 2020 Expected Penetration Case's new system peak (with solar PV) was less than the 2019 reference case peak provided by APS. The 2025 Expected Penetration Case's new system peak (with solar PV) is less than the 2024 reference case. The same comparison was completed for the High Penetration Scenario in years 2020 and 2025 as summarized in Table 2-5.

The analysis suggests for the Expected Penetration Case, the projected solar PV could delay a transmission project for a maximum of one year. Projects planned for 2019 or 2024, if any, could be postponed beyond the target years identified for this Report. Additionally, for the High Penetration Scenario, projects planned for 2023 or 2024 could be postponed beyond the 2025 target year. However, no planned transmission projects were identified in the APS Ten-Year Plan for these specific time periods.

Table 2-5
Reduced System Peak Compared to Target Load Levels (MW)

	Target Year 2020	Potential Deferral Due to Solar PV	Target Year 2025	Potential Deferral Due to Solar PV
Projected Peak Loads (no solar PV base case)	8,019	n/a	9,307	n/a
Expected Penetration Case	7,740	1 Year	8,881	1 Year
High Penetration Scenario	7,705	1 Year	8,665	2 Years
Dependable Transmission Capacity - Expected Case	279	n/a	427	n/a
Dependable Transmission Capacity - High Penetration	314	n/a	642	n/a

The dependable capacity from solar PV for the Expected Penetration Case is sufficient to result in one year of transmission load reduction, which could potentially result in deferring a transmission project for that period, and thus the potential to realize avoided costs during that year. However, as indicated above, a review of the APS 10-Year Plan did not indicate any projects scheduled to occur during 2020 or 2025 that could be impacted. For example, for the Morgan-Sun Valley 500kV line which APS currently plans to install in 2018, the analysis suggests that it could potentially be deferred by one year. However, the projected solar PV is not sufficient to reduce the system peak load to the extent that the project could be deferred beyond the 2020 target year.

Similarly, the dependable capacity from solar PV in the High Penetration Scenario is sufficient for two years of transmission load reduction by 2025; however, no projects were identified in the APS 10-Year Plan that could be impacted. Therefore it was determined that there were no planned load related transmission projects that could be deferred or avoided due to the incremental solar PV projections for the target years reviewed for this Report.

Summary of Updated Transmission System Findings

The 2009 Study determined that locating distributed solar generation near the demand (load source) benefits the transmission system by reducing the line losses across the transmission system and reducing the burden on the transmission system during peak demands, possibly allowing deferral of transmission investments. The difference between the projected system peak reduced by solar PV production and the no solar PV reference case peak is the dependable capacity for deferral of transmission projects. In this Report, actual planned transmission projects and APS loads were analyzed to determine potential deferrals.

Using the timing and costs of proposed major transmission projects provided by APS, it was determined that no load-related transmission projects could be deferred for the target years as a result of the incremental solar PV projections described in this Report.

For the 69-kV sub-transmission system, APS identified specific planned projects that could potentially be postponed by the future solar PV penetration scenarios, the amount of regional peak load reduction required and how long the project could be deferred. This was determined by evaluating the contribution of solar PV at the time of the feeder peak loads in the applicable region.

The analysis suggests that the Rural Western region is projected to have sufficient incremental solar PV capacity by 2025 to defer a 20 MW project in the High Penetration Scenario. Additionally, the Northwest region is expected to have sufficient incremental solar PV installations by 2020 in both the Expected Penetration Case and the High Penetration Scenario to postpone a 10 MW project, as well as have sufficient incremental solar capacity by 2025 to postpone a 20 MW project.

Generation (Power Supply Capacity and Energy)

Introduction

The 2009 Study summarized the generation impacts associated with distributed solar systems to the APS generation function under the overall category of Power Supply Capacity and Energy. It indicated that installing distributed solar across the APS electric system will impact the planned expansion and operation of APS generating facilities and purchase power resources, in the following ways:

- The APS system peak demand is reduced, which reduces the need for APS to add generating resources to meet peak demand growth.
- Capital and fixed operating costs associated with avoided generation units are not incurred.
- Any demand related charges associated with wholesale power purchases that are no longer needed to meet peak demand growth are reduced.
- As load requirements are reduced, the operation of APS generating units and purchase power resources (energy) are reduced, which in turn reduces the total cost of fuel, variable O&M, emissions, and power purchases.
- Solar distributed resources may increase APS requirements for Open Access Transmission Tariff (OATT) ancillary services.

There have been several assumption changes with regard to APS's generation system, which impact the results of this Report. In 2008, the APS system was experiencing significant load growth. At that time, APS had estimated that it would need to add approximately 6,000 MW of new resources through 2025, including renewable energy resources, base-load generating facilities, intermediate combined-cycle units, combustion turbine peaking units, and wholesale power purchases, as well as the implementation of approximately 600 MW of customer-based energy efficiency programs.

Since 2008, APS has experienced a reduction in its projection of future load growth as a result of the economic recession as well as the implementation of energy efficiency programs. Accordingly, APS's revised 2012 IRP includes projections of 3,800 MW of new generation by 2025, a reduction of approximately 2,200 MW.

Based on its revised load growth projections, and other factors discussed herein, the following analyses were conducted to address the potential benefits future solar PV may have on APS's resource planning and operation requirements:

- The quantity of dependable capacity available from the incremental solar PV installations was determined.
- The amount of avoided, or deferred, capital and fixed operating costs derived from the dependable solar PV capacity was projected for each solar PV penetration scenario.
- The avoided variable operating costs derived from each solar PV penetration scenario was projected for each target year reviewed for this Report. This calculation was determined from a simulation of the commitment and dispatch of APS generation and purchase power resources conducted by APS.

Capacity Value

Output from solar PV resources is only partially coincident with the peak demand of the APS load. The APS system peak is somewhat unique, in that it extends past sunset due to the impact from the desert heat. This contributes to a lower coincidence with solar PV production than otherwise would be expected with non-desert utility service territories. As such, the amount of capacity that can be relied upon from the solar PV resources is less than the total installed capacity of the solar PV resources (this concept of dependable capacity is discussed earlier in this Section). Table 2-2 provides the dependable capacities associated with the deployment scenarios analyzed in this Report.

APS Resource Plan

In 2012, APS filed their 2012 IRP with the ACC, which defines its plan for meeting the future needs of the APS customers. The plan reflects the most relevant available data at the time of this Report with regard to costs, types and timing of future resources of APS.

APS maintains a portfolio of power supply resources, which total approximately 8,800 MW, to reliably meet the needs of its customers. As of 2012, the generating resources in APS's portfolio included the following:

- 1,150 MW of nuclear capacity,
- 1,750 MW of coal-fired capacity,
- 1,850 MW of natural gas-fired combined cycle capacity, and
- 1,500 MW of natural gas-fired peaking and steam generating resources.

Additionally, APS purchases approximately 2,300 MW of wholesale power from others, including capacity from renewable resources.

Planned resources that APS can potentially avoid or delay through the implementation of solar PV on their system can be a source of value to APS. However, certain planned resources are immutable and cannot be delayed or avoided through the implementation of solar PV. These immutable resources include energy efficiency programs, planned renewable resources required to meet RES requirements, and planned base-load resources needed to enhance fuel and technology diversity in the APS portfolio. Future planned resources that can be potentially avoided or delayed through future solar PV installations include combustion turbine peaking resources, intermediate combined cycle resource, and wholesale power purchases.

For each solar PV penetration scenario, the cumulative quantity of incremental dependable capacity in each target year was compared to the planned APS generating resources. To the extent future solar PV dependable capacity is projected to be sufficient to displace the installation of one or more planned generating resources, the APS resource plan was modified to avoid or delay the installation of the generating resource(s). To the extent the future solar PV was insufficient to displace a planned combustion turbine generating unit, wholesale purchases were reduced for the quantity of available dependable capacity. The reduction in wholesale power purchases represented the net difference between APS's projected short-term power purchase needs.

To determine the marginal impacts of future solar PV, APS developed a reference base case for its resource plan. In this reference resource plan APS prepared a PROMOD review of the future generation needs for the system under an assumption that no new distributed solar PV would be installed beyond what has been installed as of the end of 2012 (see following pages for discussion of PROMOD). It should be noted that this reference resource plan was prepared specifically and solely for this Report to determine the impact of the incremental solar PV penetrations. The results of this analysis suggest that APS has sufficient generating capacity installed on its system until 2017.

For the solar PV penetration scenarios reviewed for this Report, the dependable solar PV capacity was projected to be insufficient to avoid the installation of the planned combined cycle resource. Therefore, the combined cycle resource planned by APS for installation in 2020 could not be avoided or delayed through the installation of solar PV resources.

However, the incremental dependable solar PV capacity is projected to be sufficient under the Expected Penetration Case to potentially defer two 102 MW combustion turbine resources by 2020 and three 102 MW resources by 2025 (see Table 2-6 below). Additionally, because the three 102 MW resources potentially deferred in 2025 would result in a slight capacity shortfall, the Expected Penetration Case is expected to slightly increase wholesale purchases by 10 MW in 2025.

For the Low Penetration Scenario, dependable solar PV capacity is projected to defer one 102 MW resource by 2020 and two 102 MW resources by 2025. Also, planned wholesale purchases equal to approximately 29 MW in 2025 can potentially be avoided as a result of the projections of solar PV in the Low Penetration Scenario.

Similar to the Expected Penetration Case, for the High Penetration Scenario, dependable solar PV capacity is projected to be sufficient to potentially defer two 102 MW combustion turbine resources by 2020 and three 102 MW resources by 2025. The High Penetration Scenario could also potentially avoid wholesale power purchases of approximately 45 MW in 2025.

Table 2-6
Avoided Capacity Resources

	2020 Avoided CT Resources (MW)	2025 Avoided CT Resources (MW)	2025 Avoided Wholesale Purchases (MW)[1]
Expected Penetration Case	204	306	-10
High Penetration Scenario	204	306	45
Low Penetration Scenario	102	204	29

(1) As indicated in text, the avoided wholesale purchases represent the net difference as a result of solar PV installations and deferred combustion turbine installations. The Expected Penetration Case *increases* wholesale purchases slightly in 2025.

Projected Avoided Capacity Costs

Based upon the potential avoided generating assets and avoided power purchases described above, it is possible to assign capital and fixed operating costs that APS would have incurred for these resources. These avoided costs become the basis for determining the potential savings to APS as a result of installed solar PV. Fixed avoided costs associated with the installation of solar PV as described above include:

- Capital costs associated with the avoided generating assets.
- Capital costs for transmission interconnection and system upgrades specifically assigned to the avoided generating assets.
- Fixed operating and maintenance costs of the avoided generating assets. These include annual maintenance costs, labor costs, rents and utilities, etc. that APS would incur for a generating unit whether the unit operates or not.
- Natural gas pipeline reservation fees. These are the fixed annual costs paid to the natural gas pipeline company to reserve a portion of the pipeline to serve the natural gas requirements of any avoided gas-fired generating asset.

For the purposes of this Report, the capital cost and fixed O&M assumptions developed by APS for the General Electric LMS100 combustion turbine peaking resource modeled for installation in the APS resource plan were utilized. APS estimates for transmission capital costs and natural gas reservation fees were also utilized for the purposes of this Report. In addition, avoided wholesale power purchase demand charges, which could be considered fixed costs (in the short run), were included in the variable, energy related costs. Table 2-7 below depicts the capital cost and fixed operating cost assumptions in 2013 dollars per installed kW developed by APS for this Report.

Table 2-7
Potential Avoided Capital / Fixed Operating Costs and Power Purchases (\$2013)

Combustion Turbine Installed Cost (\$/kW)	\$1,136
Transmission Installed Cost (\$/kW)	\$206
Combustion Turbine Fixed O&M (\$/kW-yr)	\$5.46
Natural Gas Pipeline Reservation Fee (\$/Decatherm-mo)	\$27.14
Wholesale Power Purchases (\$/kW-yr)	\$102.40

(1) Wholesale power purchases are included in the energy related avoided costs, see text

Solar PV Energy Value

As noted in the 2009 Study, the APS power supply portfolio resources are committed and dispatched in sufficient quantity to reliably serve APS loads each hour at the lowest reasonable cost. Resources are generally dispatched in merit order, which means that low variable cost resources are utilized more often than high variable cost resources. APS has developed models to simulate the hourly commitment and dispatch of the existing and planned resources over a long-term planning horizon (beyond 2025). These models use an industry-accepted simulation model called PROMOD, licensed by Ventyx, a recognized vendor of electric utility simulation software in the United States. APS uses PROMOD to simulate the operation of its generating and purchase power resources and to project variable operating costs of potential future power supply plans.

This Report utilizes the results from the PROMOD models developed and maintained by APS. APS has indicated that the approach, process, and assumptions for the

PROMOD modeling effort for this Report were similar or identical to those developed specifically for the 2009 Study. As in the 2009 Study, the PROMOD models include the impacts of excess energy, which is due to the APS system's minimum generation levels exceeding the system load during low load hours. SAIC reviewed the output from the PROMOD modeling effort and determined that they were reasonable.

Due to the nature of the generation resources in APS's portfolio, the energy costs avoided by solar PV installations are predominately those associated with natural gas fueled generating resources. Therefore, a primary driver of value associated with the solar PV installations is the future natural gas prices assumed in the PROMOD model.

APS indicated that it developed a forecast for natural gas prices based on forward prices observed for the New York Mercantile Exchange (NYMEX) on December 31, 2012, with appropriate price adjustments for delivery to the APS system. The delivered natural gas prices modeled by APS are referenced in Table 2-8, below. As mentioned previously in this Report, recent changes in the natural gas market have caused existing and projected prices for natural gas to fall below the estimated values used for the 2009 Study. For comparison purposes, the natural gas projections utilized in the 2009 Study have been included in the table below.

For the 2009 Study, the results of the APS PROMOD simulations were adjusted (after the fact) to include estimates for CO_2 emission allowance costs. As indicated herein, APS has developed revised adjustments to CO_2 emission allowance prices that have been included in their PROMOD simulations for this Report. For comparison purposes, the 2009 Study CO_2 prices assumed at that time are provided in Table 2-8.

Table 2-8
Projected Natural Gas Prices and CO_2 Emission Costs

	2015	2020	2025
Delivered Natural Gas Price ($/MMBtu)	4.48	5.82	7.66
CO_2 Allowance Price ($/ton)	0	15.72	22.56
For Comparison:			
2009 Delivered Natural Gas Price ($/MMBtu)	8.44	N/A(1)	9.61
2009 CO_2 Allowance Price ($/ton)	20.94	N/A(1)	52.30

(1) The 2009 Study did not include 2020 as a target year.

Generation System Methodology Conclusions

The generation system value assessment consists of calculating the value of the energy and capacity which the projected solar PV is expected to displace on the APS system. Because the solar PV installations are not able to be dispatched by APS, their electricity production is automatically input into the APS system, normally in the form of reduced energy and demand by the retail customers with solar PV.

To account for the value of the displaced energy, APS modeled the system both with and without the incremental projected solar PV. The resulting change in total system production costs (including fuel, variable O&M, emissions costs, purchased power) is the value of the displaced energy. Because APS is projecting lower levels of energy sales relative to the 2009 forecast, the value of the solar PV energy is lower due to its displacement of more efficient resources. Additionally, the lower natural gas prices used in this Report also contributes to a relatively lower value for the solar PV energy compared to the 2009 Study. Similarly, the value of the capacity additions which APS would need to install in the absence of the solar PV was calculated to the extent that the incremental solar PV is projected to preclude the need for additional capacity.

Section 3
VALUE ASSESSMENT UPDATE

This section provides the results of the updated Value Assessment completed for this Report.

Methodology for Quantification of Savings

The approach used to assess the economic value of solar PV deployment in this Report includes the following:

- Quantification of the avoided or reduced energy usage costs due to future solar PV deployment, based primarily on reduced fuel and purchased power costs.
- Quantification of the reduced capital investment costs resulting from future solar PV deployment, including the deferral of capital expenditures for distribution, transmission, and generation facilities (as appropriate).
- Estimation of the present value of these future energy and capital investment avoided costs due to future solar PV deployment.

To estimate an annual marginal economic avoided costs in the target years of 2015, 2020, and 2025 for the APS distribution, transmission, and generation functional areas under the solar PV deployment scenarios, the first step was to separate capacity and energy. This separation is important because capacity avoided costs represent value in terms of either deferral or avoided investment costs by APS, while energy avoided costs represent both immediate and ongoing cumulative benefits associated with the reduction in energy requirements.

As discussed in the 2009 Study, this methodology is consistent with the revenue requirement approach for capital investment economic evaluations that is widely accepted in the utility industry. The methodology recognizes all elements of a utility's cost to provide service, including energy components (fuel, purchased power, and operating and maintenance expenses and taxes) and capacity components (capital investment depreciation, interest expense, and net income or return requirements). It measures the reduced or avoided energy and capacity costs that APS will not incur if future solar PV is successfully deployed.

Value of Energy Avoided Costs

Future marginal energy savings associated with solar PV deployment were determined through the simulation of APS's future costs to meet the energy needs in the target years of 2015, 2020 and 2025. The operational cost avoidance for each functional area is rolled up to the reduced fuel, purchased power, emissions, and losses associated with reduced production requirements on the APS system under the solar PV penetration scenarios.

Total Annual and Present Value of Avoided Costs

Values for annual fuel, variable O&M, emissions, and purchased power avoided costs were calculated individually in the target years of 2015, 2020, and 2025. These values were added together to determine the total marginal energy avoided costs estimated to occur in these target years under the various solar PV penetration scenarios. Table 3-1 below provides these total marginal energy-related avoided costs in both nominal terms and present value 2013 dollars for the scenarios and target years identified in this Report. The present value of the nominal values as of 2013 was calculated using APS's discount rate of 7.21 percent.

Table 3-1
Energy Avoided Costs

	Incremental Solar PV (w/Losses) (MWh)	Nominal ($000)	Present Value ($000)
Expected Penetration Case			
2015	430,554	$12,988	$11,301
2020	1,397,175	$61,817	$37,984
2025	2,741,866	$162,519	$70,522
High Penetration Scenario			
2015	430,554	$12,988	$11,301
2020	1,782,433	$78,077	$47,975
2025	5,403,473	$290,257	$125,951
Low Penetration Scenario			
2015	290,132	$8,838	$7,690
2020	601,226	$28,792	$17,691
2025	1,302,165	$88,470	$38,390

Note: These energy values include the losses identified in Table 2-3.

Value of Capacity Avoided Costs

Regardless of the level of energy utilized, the utility has the responsibility to maintain a system capable of handling the coincident peak demand of its customers on each piece of equipment. The marginal capacity avoided costs associated with solar PV deployment were calculated for specific years as described herein. The identified reduction or deferral in total capacity investments in distribution, transmission, and power supply for the target years of 2015, 2020 and 2025 were discussed in Sections 2 of this Report.

These capacity cost avoided costs result in an annual reduction in APS's revenue requirements. The reduction in revenue requirements are estimated using APS's specific carrying charges calculated separately for each functional sector. An appropriate carrying charge varies each year for a specific discrete investment made in a particular year. Factors which determine the carrying charges include the accumulated capital recovery or depreciation elements, taxes, and return on investment rate base elements.

A levelized carrying charge for each utility sector was calculated to provide a reasonable estimate of avoided annual capacity costs associated with the reduction in capital investments. The levelized capacity carrying charges for the APS distribution, transmission, and generation systems are summarized in Table 3-2.

Table 3-2
Levelized Carrying Charge by Functional Sector

	Distribution System	Transmission System	Generation System
All Years	11.29%	11.05%	11.17%

These carrying charges were used along with the capacity investment savings developed in Section 2 of this Report to estimate annual values associated with the avoided or deferred capital investment costs in the distribution, transmission, and generation sectors resulting from solar PV deployment.

In addition to the deferment of direct capital investments that could potentially result from the incremental solar PV deployment discussed herein, there are reductions in costs that could also potentially be realized in the form of avoided fixed O&M costs. These avoided fixed costs are those associated with the avoided generation investments and include the associated labor, equipment and other costs associated with O&M, as well as the associated natural gas pipeline reservations fees. Due to the nature of these avoided costs, these fixed O&M costs are included in the capacity savings.

Capacity-Related Costs Avoided from Solar PV Deployment

To determine the value of deferred sub-transmission projects for the target years, only projects that were postponed from before the target year until after the target year were considered. For each of those, the regional existing solar PV was evaluated to determine the contribution at the time of the feeder peaks. Each region was evaluated to determine the potential for additional solar PV compared to expected load growth to estimate if penetration would be sufficient in those regions to defer the project.

Tables 3-3 and 3-4 below provide a summary of the annual avoided costs of the identified sub-transmission upgrades that can be deferred for the target years 2020 and 2025 for the Expected Penetration Case and the High Penetration Scenario, respectively. No sub-transmission upgrades are planned before 2015 that can be deferred, nor did the Low Penetration Scenario result in any sub-transmission projects that could be deferred for the target years.

Table 3-3
Capital Cost Deferrals at Sub-transmission Level – Expected Penetration Case

Region	MW Required	Need Date	2013 Installed Cost ($000)	Postponed Date	2020 Regional Peak Solar (MW)	2025 Regional Peak Solar (MW)	2025 Associated Annual Value ($000)
Rural Western	20 MW	2019	$7,980	2022	8	18	0
Northwest	10 MW	2021	$1,200	2026	13	30	$133
Northwest	20 MW	2021	$3,200	2026	13	30	$354
Northwest	20 MW	2017	$900	2022	13	30	0

Table 3-4
Capital Cost Deferrals at Sub-transmission Level – High Penetration Scenario

Region	MW Required	Need Date	2013 Installed Cost ($000)	Postponed Date	2020 Regional Peak Solar (MW)	2025 Regional Peak Solar (MW)	2025 Associated Annual Value ($000)
Rural Western	20 MW	2019	$7,980	2022	10	39	$882
Northwest	10 MW	2021	$1,200	2026	18	66	$133
Northwest	20 MW	2021	$3,200	2026	18	66	$354
Northwest	20 MW	2017	$900	2022	18	66	0

Table 3-3 and Table 3-4 indicate that the Rural Western region is not projected to have sufficient solar penetration based on an average feeder allocation to defer the proposed project beyond 2020 in the Expected Penetration Case but will have sufficient incremental solar PV capacity by 2025 to defer a 20 MW, $7.9 million project in the High Penetration Scenario, resulting in an annual value of approximately $882,000.

The Northwest region is expected to have sufficient incremental solar PV installations by 2020 in the both the Expected Penetration Case and the High Penetration Scenario to postpone a 10 MW, $1.2 million project, resulting in annual value of approximately $133,000 as well as have sufficient incremental solar capacity by 2025 to postpone a 20 MW, $3.2 million project, resulting in an annual value of approximately $354,000.

Table 3-5 provides a summary of generation related transmission system capital cost reductions associated with the deployment of solar PV by penetration scenario. The first column of this table represents the value of the cumulative installed capacity cost reduction and the second column represents the resulting associated annual cost avoidance in nominal dollars. The third column represents the present value of the nominal dollars, using APS's discount rate of 7.21 percent. As noted previously, the solar PV penetration scenarios did not provide sufficient dependable capacity to avoid or defer any load related transmission level projects.

Table 3-5
Generation Related Transmission Capital Cost Reductions

	Cumulative Installed Capacity Cost Reductions ($000)	Associated Annual Value – Nominal ($000)	Present Value ($000)
Expected Penetration Case			
2015	$0	$0	$0
2020	$46,969	$5,190	$3,189
2025	$73,884	$8,164	$3,543
High Penetration Scenario			
2015	$0	$0	$0
2020	$46,969	$5,190	$3,189
2025	$73,211	$8,090	$3,510
Low Penetration Scenario			
2015	$0	$0	$0
2020	$23,194	$2,563	$1,575
2025	$49,437	$5,463	$2,370

Table 3-6 provides a summary of generation system capital cost reductions associated with the deployment of solar PV by penetration scenario. Generation capital cost reductions were determined to exist for the Expected Penetration Case and the Low and High Penetration Scenarios. Similar to the previous table, the first column represents the value of the cumulative installed capacity cost reduction, the second column represents the resulting associated annual cost avoidance, and the third column represents the present value of the cost avoidance.

Table 3-6
Capital Cost Reductions at Generation Level

	Cumulative Installed Capacity Cost Reductions ($000)	Associated Annual Value – Nominal ($000)	Present Value (1) ($000)
Expected Penetration Case			
2015	$0	$0	$0
2020	$258,917	$28,926	$17,774
2025	$407,286	$45,502	$19,744
High Penetration Scenario			
2015	$0	$0	$0
2020	$258,917	$28,926	$17,774
2025	$403,579	$45,087	$19,565
Low Penetration Scenario			
2015	$0	$0	$0
2020	$127,860	$14,284	$8,777
2025	$272,523	$30,446	$13,211

(1) The present value of these future savings as of 2013 was calculated using APS's discount rate of 7.21 percent.

Table 3-7 provides a summary of the estimated Fixed O&M cost avoidance associated with the deployment of solar PV by penetration scenario. As indicated previously, these costs are associated with the deferment or avoidance of the generation investments and include fixed costs (such as labor) and pipeline reservation related costs.

Table 3-7
Fixed O&M Related Avoided Costs

	Nominal Value ($000)	Present Value [1] ($000)
Expected Penetration Case		
2015	$0	$0
2020	$4,668	$2,868
2025	$7,926	$3,438
High Penetration Case		
2015	$0	$0
2020	$4,668	$2,868
2025	$7.926	$3,438
Low Penetration Case		
2015	$0	$0
2020	$2,334	$1,434
2025	$5,282	$2,292

(1) The present value of these future savings as of 2013 was calculated using APS's discount rate of 7.21 percent.

Table 3-8 provides a summary of the capacity related avoided costs associated with the deployment of solar PV by penetration scenario. This table represents the summation of the sub-transmission, generation and Fixed O&M avoided costs identified above.

Table 3-8
Total Capacity Related Avoided Costs

	Nominal Value ($000)	Present Value (1) ($000)
Expected Penetration Case		
2015	$0	$0
2020	$38,784	$23,831
2025	$62,074	$26,936
High Penetration Case		
2015	$0	$0
2020	$38,784	$23,831
2025	$62,468	$27,107
Low Penetration Case		
2015	$0	$0
2020	$19,182	$11,786
2025	$41,190	$17,874

(1) The present value of these future savings as of 2013 was calculated using APS's discount rate of 7.21 percent.

Table 3-9 provides a summary of the total estimated marginal solar PV deployment avoided costs for the Expected Penetration Case and the Low and High Penetration Scenarios, in total and on a unit ($/MWh) basis. Table 3-9 represents the summation of the energy and capacity related avoided costs presented in the tables above, and includes their present value in 2013 dollars, utilizing APS's discount rate of 7.21 percent.

Table 3-9
Total Solar PV Value

	Total Annual Avoided Costs ($000)	Estimated Incremental MWh (w/ losses) Savings	Estimated Unit Avoided Costs ($/MWh)	Present Value ($000)
Expected Penetration Case				
2015	$12,988	430,554	$30.17	$11,301
2020	$100,601	1,397,175	$72.00	$61,815
2025	$224,593	2,741,866	$81.91	$97,457
High Penetration Scenario				
2015	$12,988	430,554	$30.17	$11,301
2020	$116,861	1,782,433	$65.56	$71,807
2025	$352,725	5,403,473	$65.28	$153,058
Low Penetration Scenario				
2015	$8,838	290,132	$30.46	$7,960
2020	$47,973	601,226	$79.79	$29,478
2025	$129,661	1,302,165	$99.57	$56,264

Note: Total Annual Value represents sum of value categories by penetration scenario. The energy savings equals the values in Table 2-1.

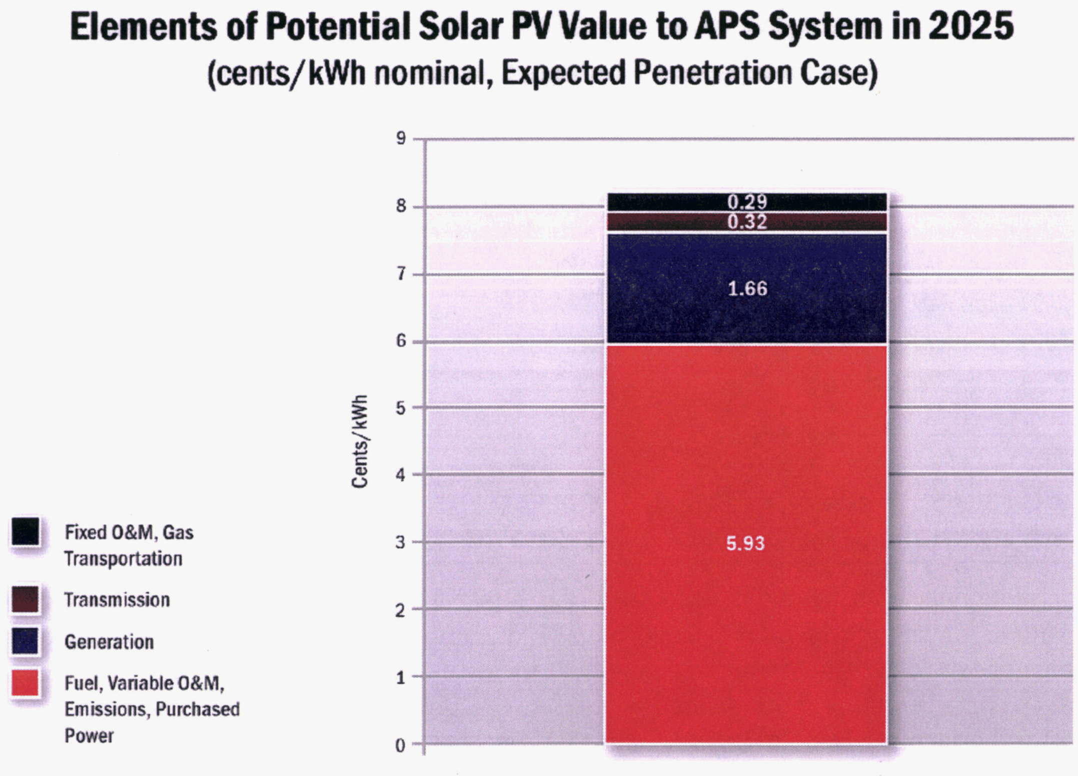
Table 3-10 below provides a summary of the present value associated with the estimated incremental avoided costs for the solar PV penetration scenarios for the target years of this Report.

Table 3-10
Total Solar PV Value (Present Value)

	Total Annual Avoided Costs ($000)	Estimated Incremental MWh (w/Losses) Savings	Estimated Unit Avoided Costs ($/MWh)
Expected Penetration Case			
2015	$11,301	430,554	$26.25
2020	$61,815	1,397,175	$44.24
2025	$97,457	2,741,866	$35.54
High Penetration Scenario			
2015	$11,301	430,554	$26.25
2020	$71,807	1,782,433	$40.29
2025	$153,058	5,403,473	$28.33
Low Penetration Scenario			
2015	$7,690	290,132	$26.51
2020	$29,478	601,226	$49.03
2025	$56,264	1,302,165	$43.21

2013 Solar PV Update

The total solar PV value of the functional elements for 2025 (in nominal dollars) for APS are represented in Figure 3-1. This figure includes the present value of the functional element values for comparison purposes.



	2025 Nominal Value (cents/kWh)	Present Value (cents/kWh)
Distribution	0.00	0.00
Fixed O&M, Gas Transportation	0.29	0.13
Transmission	0.32	0.14
Generation	1.66	0.72
Fuel, Variable O&M, Emissions, Purchased Power	5.93	2.57
Total (cents/kWh)	8.19	3.56

Note

This graphic assumes the following:

- Natural gas price of $7.66/MMBtu in 2025.
- Incremental savings (including losses) from solar PV of approximately 2,741 GWh in 2025.
- Avoidance of approximately 306 MW of thermal generation resources (and associated transmission facilities) in 2025.
- Assumes market driven deployment of flat plate arrays. No location specific deployment scenario or single axis tracking solar PV scenario.
- Incremental value for avoided CO_2 emission related costs assumed to be $22.00/ton in 2025.
- Values are rounded to three decimal places (0.001 cents/kWh) and may not total due to rounding.
- Present value is 2025 nominal value utilizing APS's discount rate of 7.21 percent.

Figure 3-1: Elements of Potential Solar PV Value to APS System in 2025 (Expected Penetration Case)

Comparison to 2009 Study

The results of this Report provided in Figure 3-1 above represents the Expected Penetration case for solar PV in 2025. The estimates of total solar PV value for the 2009 Study for comparison by deployment scenario are provided below. Table 3-11 below provides a comparison of the scenarios developed for this Report to the 2009 Study results for 2025 in nominal dollars.

Table 3-11
2013 Report Comparison to 2009 Study ($ Nominal)

2025 Target Year	Total Solar DE / PV Avoided Costs ($000)	Estimated MWh Savings	Estimated Unit Avoided Costs ($/MWh)
2009 – Low Penetration Case (DE)	$18,679	176,009	$106.12
2009 – Medium Penetration Case (DE)	$208,924	1,788,610	$116.81
2009 – High Penetration Case (DE)	$382,307	3,862,585	$98.98
2013 – Low Penetration Scenario (PV)	$129,661	1,302,165	$99.57
2013 – Expected Penetration Case (PV)	$224,593	2,741,866	$81.91
2013 – High Penetration Scenario (PV)	$352,725	5,403,473	$65.28

The reduction in unit avoided costs from the 2009 Study to this Report is the result of a variety of change in market conditions. The primary difference provided in the tables above relates the dramatic changes in the estimated incremental energy savings (MWh) between the various scenarios run for the 2009 Study and this Report. This is due to the increased deployment of solar PV observed by APS in its service territory since the time of the 2009 Study, as well as changes in the underlying assumptions around the high and low sensitivities. The total avoided costs for the 2009 Study were influenced by the other technologies reviewed for that study (residential solar hot water and commercial daylighting). The changes in assumptions discussed throughout this Report also influence the avoided costs, the energy savings and the resulting estimated unit avoided costs. However, the main variances that can be attributed to the value categories are as follows:

- The distribution system avoided cost from reductions in capacity is shown to be zero for this Report. This represents the results of market-based projection of solar PV penetration assumed in this Report compared to the targeted placement projections assumed in the 2009 Study.
- The fixed O&M avoided costs have been reduced based on associated type and amount of planned generation that is avoided as a result of the increased solar PV penetration. Additionally, for the 2009 Study, the fixed O&M category included market power purchases for capacity, as well as fuel transportation costs. The market power purchases are included in the Fuel, Variable O&M, Emissions and Purchased Power category in this Report.
- The transmission avoided costs are projected to be the transmission investments associated with the avoided generation and are similar to the values estimated in

the 2009 Study. The capacity costs from the avoidance of generation investment is also similar to the values determined for the 2009 Study.

- The variable avoided costs (fuel, variable O&M, emissions and purchased power) are slightly below the range estimated by the 2009 Study, however as indicated above, the values in this category developed for this Report include purchased power capacity costs, which were included in the fixed O&M cost category for the 2009 Study. The primary driver of value in this category is the fuel price associated with the avoided energy projections.

Summary of Report Methodology Changes

This Report provides an update of the valuation of solar resources developed in the 2009 Study. This update was precipitated by several changes regarding assumptions utilized for the 2009 Study, including those in the power market and APS operations, as well as observations from the solar PV installations and other factors. This Report utilized the methodology and process developed for the 2009 Study to the extent possible in the determination of the value of solar PV for APS, with the exceptions noted herein. A summary of these changes in methodology and assumptions is listed below:

- The existing and projected costs for APS to produce and/or purchase power from the market have lowered dramatically since the 2009 Study, primarily as a result of lower natural gas prices used as a fuel source for electric generation In 2008, market natural gas prices were approximately $9.00 per MMBtu; in 2012 natural gas prices were approximately $3.50 per MMBtu.
- Emission costs for CO_2 utilized for this Report are projected to begin in 2019 and are assumed to escalate to a value of approximately $22.00 per ton in 2025, which represents a reduction in the CO_2 emissions costs utilized for the 2009 Study.
- The number of installed distributed solar PV systems in the APS service territory has increased dramatically since the 2009 Study. In 2008, APS had under 1,000 solar PV systems installed on its system, whereas by the end of 2012, this number had increased to over 14,000.
- APS reports that only a very small percentage of the solar PV systems installed utilize single-axis tracking technologies. The scenario analysis developed for this Report could reasonably be considered to include output from the relatively small number of existing and expected single-axis tracking systems installed on the APS system.
- APS's solar PV incentive programs have allowed the organic market growth for solar PV deployment. This market growth has not resulted in significant localized penetration regions, but instead these installations have been geographically spread-out across the APS service territory. This Report assumes future deployment locations consistent with the observations of existing penetrations to date.

- Total load (demand and energy use) projections for APS customers are lower than the forecasts utilized in the 2009 Study due to the economic recession and as well as the state of Arizona energy efficiency standards that have reduced both energy and demand projections.
- The 2009 Study estimated the value of marginal avoided losses for distributed solar systems utilizing a theoretical approach. APS has reported that it is not been technically feasible to verify the accuracy of this estimate. Therefore, this Report utilizes known system average energy and demand losses observed and measured by APS in its approach to value the avoided losses.

Conclusions

The primary element of the value for solar PV is the avoided energy related costs that are displaced by the incremental solar PV production (as indicated in Figure 3-1 for the Expected Penetration Case in 2025). These variable related costs include:

- Fuel (primarily natural gas commodity)
- Purchased power (avoided capacity (demand) costs associated with changes in purchased power from the wholesale power market),
- Variable O&M costs (reduction in costs associated with avoidance of future generation resource)
- Emission related costs for thermal power plants (including CO_2, as well as others), and
- Energy savings associated with avoided losses (the energy that would have been required to be generated at a centralized facility and lost due to the physics of energy transmission).

The avoided fuel costs represent the largest contribution of the four elements included in this value category. Combined, this value category is estimated to represent approximately 70 percent of the total value for incremental solar PV on the APS system.

The next highest value category of solar PV value in 2025 is associated with avoidance of generation capacity. This value is derived from the investment value required by APS to fund future generation that is avoided by the incremental solar PV dependable capacity estimated to be installed at that time. The avoided generation capacity developed by APS for this Report consists entirely of combustion turbine units. The avoided generation capacity value represents approximately 20 percent of the total value of the solar PV in 2025.

The remaining value categories determined for solar PV in 2025 include avoided transmission capacity costs and fixed O&M costs. The transmission capacity relates to the avoided or delayed transmission projects (associated with generation planning) due to the projected incremental solar PV penetration. The fixed O&M values are related to the generation resources mentioned above and are associated with the avoided operation of those power plants (whereas the capacity is the estimated avoided investment), as well as the associated fuel transportation reserve charges for those facilities.

Combined, the transmission capacity and fixed O&M avoided costs account for approximately 10 percent of the total estimated incremental solar PV value to APS in 2025. The distribution capacity avoided costs is estimated to be zero, because this value category requires solar PV to be installed at specific locations on the APS distribution system. Reductions in capital costs for distribution capacity investment from existing and projected solar PV installations as described herein, was found to be insignificant.

As indicated previously, the projected solar PV penetration would be expected to shift the hour of the system peak demand due to the contribution from the dependable capacity at the time of the peak. The results of the analysis developed for this Report suggests that for the Expected Penetration Case and the High Penetration Scenario, the incremental solar PV is sufficient to shift the system peak demand hour from 5:00 p.m. (in the reference case) to 6:00 p.m. for the target years 2020 and 2025. However, the incremental solar PV is not sufficient under any of the scenarios analyzed herein to result in a shift in the system peak demand hour in 2015. Additionally, the solar PV projections in the Low Penetration Scenario are not sufficient to shift the hour of peak demand for any of the target years identified in this Report.

Value Assessment

In general, the values determined for the incremental solar PV for the early period of this Report (2015) are zero for the capacity related assessment. APS does not have a projected need for additional traditional (thermal) generation resources until 2017, therefore, the soonest target year that solar PV can delay or offset these resources is 2020. Additionally, the year 2015 is too close to the existing year (2013) for the incremental solar PV to impact capital resource planning needs that often are several years in the planning. In the short term (next two years) the solar PV penetration is not sufficient, even in the High Penetration Scenario, to impact these capital decisions. However, the early period of this Report does result in energy savings as a result of the projected incremental solar PV installations.

Increased incremental solar PV penetration results in decreased costs to APS. However, this relationship is not linear. The incremental dependable capacity declines somewhat exponentially with the installation of each new system. Therefore, incremental solar PV installations in the future could reach a point in which APS no longer receives any new capacity benefits. Thus the impact on demand reduction to the system (and the resulting decrease in need for future generation and related transmission investment) does not decrease on a one-to-one basis with the installation of new solar PV systems. This result is expected and is consistent with the results of the 2009 Study.

On a unit basis ($/MWh), the results indicate a higher avoided costs for lower incremental solar PV (comparing the Expected Penetration Case to the Low Penetration Scenarios in Tables 3-9 and 3-10 above). This is due to the rate of change in total avoided costs ($) relative to the rate of change in avoided energy (MWh). The total avoided costs is the combination of variable and fixed avoided costs. Avoided variable costs generally increase proportionally to avoided energy, however, the avoided fixed costs do not. The avoided fixed costs are "lumpy"; the incremental solar PV penetration must exceed a threshold before these capital investment savings can be realized.

Additionally, avoided fixed costs are a function of the dependable capacity. As discussed herein, incremental dependable capacity declines somewhat exponentially with the installation of each new system, therefore as solar PV penetration increases, the benefit from the dependable capacity decreases. The combined effect is a lower relative contribution to total value from avoided fixed costs in the higher penetration scenarios. Combined with the changes in avoided energy across the scenarios, the result is higher avoided costs on a unit basis for lower solar PV penetration for 2020 and 2025.

This Report suggests that without significant targeted placement of solar PV, there is no capacity value to the distribution system. This is primarily a results of the difference in timing between the hour of peak demand of the feeders along the distribution system and the hour of peak production for the solar PV system. To create capacity value in the distribution system, the solar PV would need to be sufficient to reduce load to below 90 percent of a specific feeder's rated capacity at the time of peak. The analysis conducted for this Report suggests that the number of feeders on the APS system that could potentially benefit from this reduction from solar PV was insignificant, therefore resulting in zero capacity-related cost reductions for the distribution system.

As indicated herein, the methods and process developed for this Report were generally consistent with those utilized for the 2009 Study. The estimated results of this Report for 2025 are within the range of the values estimated for the 2009 Study. This suggests that the sound methodology developed for the 2009 Study, and to some extent updated herein, is capable of being reproduced to estimate solar PV value to APS in the future.