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Part 2 of 5

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For parts 3-5, see barcodes 0000171009, 0000171040 + 0000171041

DIRECT TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

EXHIBIT
APS-1
ADMITTED

February 25, 2016

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DIRECT TESTIMONY OF LELAND R. SNOOK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Leland R. Snook. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Director of Rates and Rate Strategy for Arizona Public Service Company ("APS" or "Company"). I have management responsibility for all aspects relating to rate strategy and specific rates and prices.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My background and experience are set forth in Attachment LRS-1 to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. In my direct testimony I provide:

1. A summary of APS's conclusions and recommendations in this docket;
2. An overview of the APS testimony and witnesses in this proceeding;
3. The cost of service study ("COSS") that APS filed in this docket, including the methods that APS used to create the COSS, the results of the COSS and the implications of those results; and,
4. Direct responses to a portion of Chairman Little's questions set forth in his December 22, 2015 letter related to my testimony.

II. SUMMARY OF RECOMMENDATIONS

Q. MR. SNOOK, PLEASE SUMMARIZE THE COMPANY'S CONCLUSIONS AND RECOMMENDATIONS IN THIS DOCKET.

A. First, because rates are based on historical test year data, the Commission should adopt the Company's COSS methodology as set forth in this docket. Further, the Commission should find and conclude as a policy matter that Value of Solar methodologies will not be used in setting rates.

Second, the methodology for determining Value of Solar established by the Commission as a result of this docket should be approved as an appropriate analysis tool for determining (i) the value of solar in the resource planning context; and (ii) calibrating the price paid for energy exported to the grid from rooftop solar arrays.

III. OVERVIEW OF APS TESTIMONY

Q. PLEASE PROVIDE AN OVERVIEW OF THE APS WITNESSES IN THIS PROCEEDING.

A. In this proceeding APS is presenting testimony from four witnesses in its Direct Testimony. In addition to my own testimony on the COSS, APS is presenting testimony from:

- Ashley C. Brown, Executive Director of the Harvard Energy Policy Group, who will provide a national and policy perspective on the value of solar and related studies.
- Bradley Albert, APS's General Manager of Resource Management, Power Marketing and Acquisitions, who will describe several methods for calculating the value of residential distributed solar photovoltaics, including the various

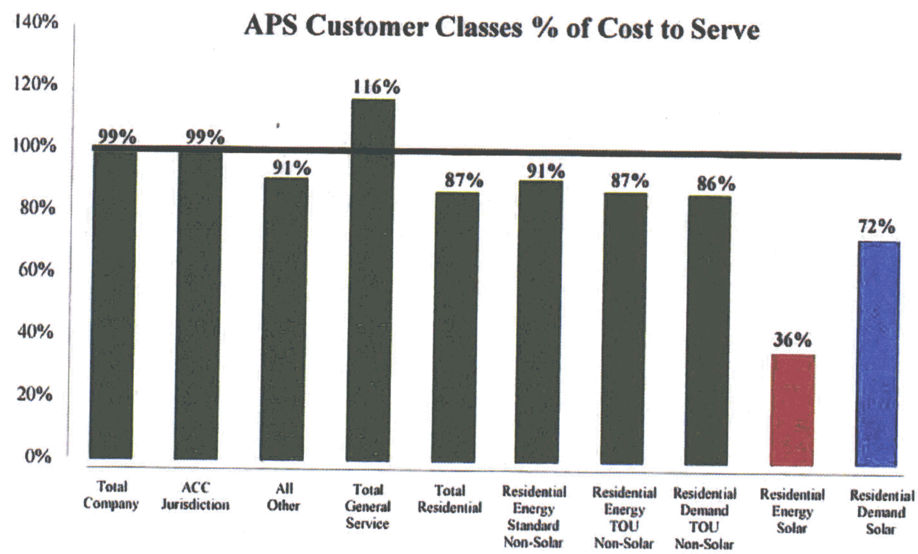
value attributes. Mr. Albert will also discuss various methodologies for arriving at the value of solar.

- John Sterling, Solar Electric Power Association's ("SEPA") Senior Director, Research & Advisory Services, who will provide an overview of SEPA's work with the Tennessee Valley Authority on their recent value of solar study and the results, which addressed many of the issues that are the subject of this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony first discusses the methods and results of the COSS that APS prepared in connection with this proceeding. The COSS demonstrates that residential rooftop solar customers, also referred to as Net Energy Metering ("NEM") customers, on energy-based rates pay only 36% of the cost to serve them, and that NEM customers on demand rates pay only approximately 72% of the cost to serve them. This is in contrast to residential customers without solar, who pay between 86% and 91% of the cost to provide them electric service. These COSS results demonstrate that the cost shift is real under APS's present rate design. If rate design is not modernized, approximately $67 per month in cost responsibility for solar customers on energy rates and $29 per month for solar customers on demand rates will be shifted to residential customers without solar — to the extent these fixed costs are not already being shifted through APS's Lost Fixed Cost Recovery Mechanism. Figure 1 below displays the percent of cost to serve results from the COSS, reflecting the amount that is being paid under current rate structures for all customer groups, in relation to the cost of providing service.

Figure 1.



Further, the COSS demonstrates that today, without the right price signals to incent behavior, the demand and energy usage of residential customers with rooftop solar differs significantly from residential customers without solar. These differences make it appropriate to evaluate, for ratemaking purposes, residential solar customers as a unique sub-class within the residential customer group.

Lastly, I discuss the implications of the COSS results. Relying on a kWh price for the bulk of cost recovery is no longer a workable solution. When customers reduce energy use only, and don't reduce fixed grid costs, current rate design shifts responsibility for fixed cost recovery to customers without rooftop solar. This cost shift will increase rates for those customers without solar, including the most vulnerable of our customers, the limited-income segment, without regard for cost causation. This is inequitable and must change for solar to be a sustainable technology for all customers over the long term. Further, volumetric rates pick which technologies win and which lose. Currently, only those technologies that reduce energy can permit customers to reduce their bills. Aligning costs with cost recovery, however, will permit different technology types to compete based on how effectively they reduce costs. The result will provide customers with more and more choices as technological innovation continues.

The COSS reflects what APS believes to be the appropriate method to use in rate case proceedings for the cost of service analysis for rooftop solar customers. It also supports realigning rate design to better match the costs incurred to serve customers. Realigning rates will help ensure that:

- Customers have accurate price signals from which to make efficient energy technology decisions;
- Prices for services are equitable for all customers, including both those that adopt technology and those who do not; and,
- The pricing framework is financially sustainable for all customers over the long term.

If a customer no longer consumes significant amounts of energy but continues to use infrastructure assets, APS's pricing structure must appropriately measure and bill for this changed, but ongoing, use in a manner that is fair for all customers. The current method of collecting fixed and demand-related costs on a fluctuating kilowatt-hour ("kWh") energy basis will not achieve this critical goal.

Q. PLEASE DESCRIBE THE SUMMARY SCHEDULES THAT SUPPORT THE COSS THAT YOU ARE SPONSORING.

A. The Summary Schedules provide detailed information regarding the Company's COSS. These schedules illustrate the jurisdictional allocation of costs to both retail (Arizona Corporation Commission ["ACC" or "Commission"]) and non-retail (predominantly Federal Energy Regulatory Commission ["FERC"] regulated services which are designated as "All Other"). Further, the Summary Schedules functionalize costs to each broad customer class and specific customer sub-classes, ultimately deriving the percentage of cost to serve that is being recovered under current rates, based on original cost by class and sub-class. The Summary Schedules also contain all cost-allocation factors used in preparing the study.

The following is a summary of these Schedules:

- Summary Schedule 1 shows the rate-of-return at existing rates by customer class, based on the unadjusted 2014 Test Year COSS. (Attachment LRS-2DR)
- Summary Schedule 2 shows the functionalized dollar amount and percentage of rate base allocated to each retail customer class. (Attachment LRS-3DR)
- Summary Schedule 3 shows the functionalized amount of operating expenses allocated to each retail customer class. (Attachment LRS-4DR)
- Summary Schedule 4 shows the amount of functionalized rate base allocated to ACC jurisdictional customers. (Attachment LRS-5DR)
- Summary Schedule 5 shows the amount of functionalized operating expense allocated to ACC jurisdictional customers. (Attachment LRS-6DR)
- Summary Schedule 6 lists the allocation factors used in preparing the 2014 Test Year COSS. (Attachment LRS-7DR)

Q. DO YOU SPONSOR ANY ADDITIONAL SCHEDULES RELATED TO THE COST OF SERVICE?

A. Yes. Attachment LRS-8DR to my testimony is the COSS Schedule, which is a summary showing:

1. Jurisdictional separation of rate-base costs, revenues, and operating expenses between the ACC and All Other jurisdictions;
2. Further allocation by retail customer class, of total ACC allocated costs and the percentage of cost to serve paid by each major customer class;
3. The same information by each general service sub-class; and,

4. The same information by each residential service sub-class, including the NEM energy and demand rate sub-classes.

IV. COST OF SERVICE STUDY

Q. WHAT IS A COST OF SERVICE STUDY?

A. A COSS is the fundamental tool for allocating a utility's costs among its customers based upon their responsibility for incurring such costs. It is foundational in developing appropriate pricing structures that align the rates customers pay for the services received with the customers who are driving the costs. This is often described as the "cost causation principle."

A COSS is a detailed analysis of audited financial information and actual customer load data that assesses the responsibility of each customer group for the costs incurred to provide service during the relevant time period. The COSS functionalizes, classifies, and then allocates costs and revenues, beginning with wholesale and retail customers, then continuing the process with various broad classes of retail service and finally to sub-classes within each retail class.

The cost-allocation study enables APS to determine its unit costs, by function, incurred to provide energy, demand, and customer services to each customer class and sub-class, as well as the support to those costs that each customer group presently contributes through their rates.

The ACC, and public utility commissions across the country, use cost-of-service studies developed in this manner to set rates for most public utilities, including water, electric, and gas utilities.

Q. WHAT TIMEFRAME DID THE COMPANY USE FOR THE COST OF SERVICE STUDY THAT IT FILED IN THIS DOCKET?

A. APS conducted an embedded COSS using data from the most-recent calendar year available — the twelve-month period ending December 31, 2014 — as the test period ("Test Year").[1] The Company analyzed its costs, customer class sales and load characteristics during this period — the number of customers and their demand and energy usage is commonly referred to as "Billing Determinants" — and used those results to allocate the various plant and operating expenses to each customer class through a rigorous process of functionalization, classification, and allocation of costs. The study results allow APS to derive the percentage of cost to serve that is being recovered under current rates, based on original cost, by class and sub-class.

Q. WHAT DO YOU MEAN BY EMBEDDED COSS?

A. An embedded COSS is based on the historical costs and operating experience of the utility during the selected Test Year. Rate-making in Arizona is based on this historical Test Year and embedded cost approach. Under this method, rates are based on actual incurred costs as verified through audited financial data.

Q. PLEASE DISCUSS THE DEVELOPMENT OF THE EMBEDDED COST ALLOCATION STUDY.

A. This study was prepared using industry-accepted Cost of Service Functionalization, Classification, and Allocation principles, and is consistent with Commission-approved methods.

Functionalization refers to the process of attributing each rate base or expense item to a particular function — namely Production (generation of electricity), Transmission,

[1] Note that APS will use the next year, ending December 31, 2015, for the COSS in the rate case that APS will file in June 2016. As the year immediately preceding APS's rate case filing, 2015 is the most recent full calendar year upon which to base rates and will be the test year for the rate case.

Distribution or Customer Service (e.g., metering and billing) — in the provision of electric service. An example is assigning the costs of building and operating the Company's generation power plants to the Production function.

Classification refers to the process of determining the factor or factors that drive the magnitude of the cost. For example:

- If a cost to serve is driven by the amount of kWh energy consumed, such as fuel cost, it is classified as Energy.

- If a cost is driven by the rate at which energy is consumed, or kW capacity, it is classified as Demand.

- If a cost is driven by the number of customers taking service on the APS system irrespective of either the kW demand or kWh energy, it is classified as Customer.

Allocation occurs after a cost has been functionalized and classified. This is the process in which allocation factors — such as class coincident peak demand contribution at the time of system peak, non-coincident class peak ("NCP") or the sum of individual peaks, energy or number of customers — are applied to allocate the costs to particular jurisdictions, customer classes, and rate schedules or sub-classes. A simple example is the allocation of energy-related costs by kWh consumption to different customer classes.

In summary, in the COSS the expense and rate-base items that comprise all of APS's costs were grouped into major categories, such as Plant in Service or Operating & Maintenance ("O&M") Expense. Each of these categories was first functionalized into Production, Transmission, Distribution or Customer related costs, then classified as Demand, Energy, or Customer-related. Allocation factors based on kW, kWh and number of customers were then developed so that the functionalized and classified costs could be allocated to the ACC retail jurisdiction and to the various retail customer classes and sub-classes.

Q. HOW DID YOU ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?

A. Production-related assets are generally designed and built to enable the Company to meet its system peak load. Therefore, the costs associated with these investments are allocated between jurisdictions based on the average of the system peak demands occurring in the four summer months of June, July, August, and September (referred to as "4CP") to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its rate cases before FERC, and creates jurisdictional alignment to ensure the right proportion of cost is being allocated to each jurisdiction. It also eliminates the potential that costs, due to differences in allocation methods, cannot be recovered from either jurisdiction. It has also been accepted as the jurisdictional allocation methodology by the Commission for many years.

Within the ACC-jurisdictional customer classes, production costs were allocated based on the Average and Excess Demand ("AED") method. This is a method required by the Commission in Decision No. 69663 (June 28, 2007). AED uses the sum of two demand allocators:

1. **NCP Average Demand allocator**, which uses each class's NCP demand weighted by the class load factor calculated using the class energy and the NCP demand.

2. **System Peak Excess Demand allocator**, which is determined by first calculating the NCP Excess Demand, which is the difference between each class's NCP and that class's average demand. Second, the sum of NCP Average

Demands is subtracted from the single system peak demand to derive the System Peak Excess Demand, which is then allocated to each class based on the proportionate share of the sum of NCP Excess Demands.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the Cost of Service Study. A portion of transmission costs are brought back into the ACC jurisdictional cost of service to offset the existing Open Access Transmission Tariff ("OATT") revenues to ensure there is no double-counting of transmission costs between the ACC and non-ACC jurisdictions. This also effectively assumes that each customer class pays the cost of transmission service even though this is demonstrably not the case for solar customers.

Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class's peak load, which may or may not be coincident with the system peak load. Thus, allocation of costs related to distribution substations and primary distribution lines are made based on NCP loads. Allocation of costs related to distribution transformers and secondary distribution lines are made based on the summation of the individual peak loads or demands of all customers within a particular customer class ("Sum of Individual Max"). Each of these allocation methods has traditionally been used by APS and accepted by the Commission for many years.

Q. HOW DID YOU DETERMINE IT WAS APPROPRIATE TO CREATE A SEPARATE RESIDENTIAL SUB-CLASS FOR NEM ENERGY AND NEM DEMAND CUSTOMERS WITHIN THE RESIDENTIAL CUSTOMER CLASS?

A. It can be appropriate to create a new class or sub-class of customers for purposes of a COSS or setting rates if the service, load, or cost characteristics of the customer sub-group in question are sufficiently different from their current customer classification. Upon reviewing these characteristics for customers with solar, I determined that sufficient differences exist for at least separately studying this sub-class of residential customers in a COSS.

When evaluating the load characteristics of residential customers with and without rooftop solar, the peak demand — CP, NCP and Sum of Individual Max — and energy characteristics are very different for solar customers. The typical residential solar customer still needs about 81% of the capacity they used before they adopted solar and 30% of the energy. This is a significantly different profile than residential customers without solar, regardless of size.

Second, in the 2014 Test-Year, APS had more than 27,000 solar customers on an energy rate and almost 1,200 solar customers on a demand rate by year's end. The size of this residential solar customer sub-group, combined with its vastly different load characteristics, warrant evaluating them as a separate sub-class. See Figures 2 and 3 for a comparison of typical solar and non-solar customer daily load shapes for a summer and winter day.

Figure 2.

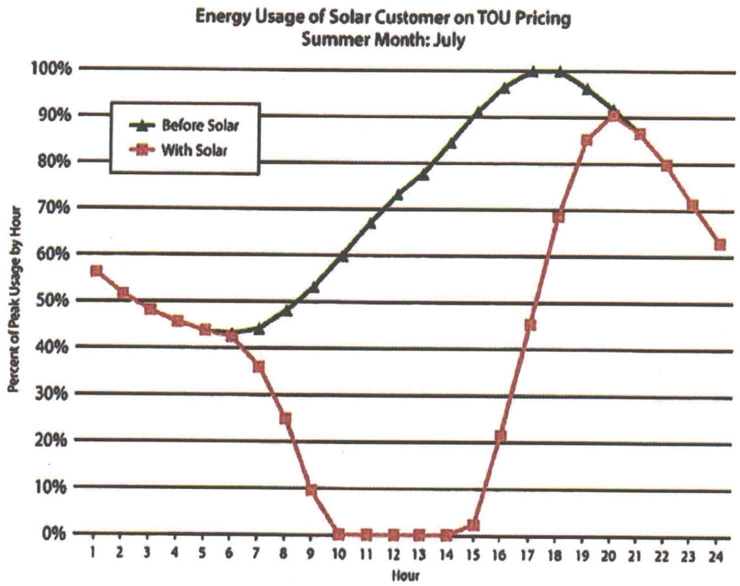
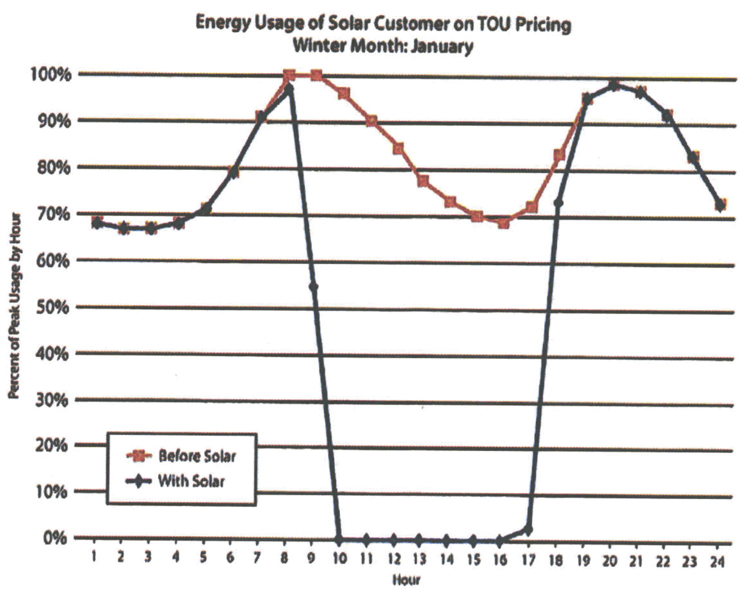


Figure 3.



Also, the Public Utilities Commission of Nevada ("PUCN") found that it is appropriate to evaluate NEM customers as a separate sub-class based on significant cost and load differences:

> It is just and reasonable and in the public interest to establish separate rate classes for *all* NEM ratepayers based on both the cost differentiation and load (usage) differentiation between NEM ratepayers and non-NEM ratepayers. Different services have different costs and thus require different rate classes. NEM ratepayers are partial-requirements service ratepayers. The Commission has historically established separate, optional rate schedules for ratepayers who self-select to become partial-requirements ratepayers. Partial-requirements service ratepayers are ratepayers whose electric requirements are partially or totally provided by non-utility generation. There is a significant difference in the load (usage) profiles between partial-requirements NEM ratepayers and full-requirement ratepayers. NEM ratepayers can rapidly go from exporting unused electricity to importing needed electricity from the local grid. As a result, NV Energy provides a distinct service to partial-requirements ratepayers who choose to purchase some, but not all, of their energy needs from the utilities.[2]

The PUCN also found that the load levels and hourly usage differences of NEM customers alone justified a separate rate class:

> Besides the partial-requirements nature of NEM ratepayers' service, the load levels and hourly usage differences between NEM and non-NEM ratepayers are sufficient (alone) to justify separate ratepayer classes for NEM ratepayers. There is a significant difference between the load shapes (usage profiles) of NEM and non-NEM ratepayers, thus supporting the establishment of new NEM ratepayer classes. The total load and delivered load of the NEM ratepayer is distinct and varies from the shape of non-NEM ratepayers on an hourly basis.[3]

I agree with the Nevada Commission. It is true that some differences exist between NV Energy's system and APS's system. However, those differences are limited, and only concern quantifying the objective magnitude of these differences, not the relative significance or whether these differences exist in the first place. The physics underlying

[2] Modified Final Order in Docket Nos. 15-07041 and 15-07042, at Paragraph 91 (February 17, 2016) (emphasis in original).
[3] *Id.*, at Paragraph 92.

electrical service are the same in Arizona as they are in Nevada. And the service, load, and cost differences regarding NEM customers found by the Nevada Commission are the same differences experienced by APS in relation to APS's solar customers.

Q. PLEASE EXPLAIN THE PROCESS THAT APS USED TO CREATE A UNIQUE RESIDENTIAL SUB-CLASS FOR NEM CUSTOMERS.

A. Consistent with the methodology I previously discussed:

1. APS grouped NEM customers currently on energy-based rate schedules, which includes customers both on inclining block and time-of-use rate schedules.

2. APS separately grouped NEM customers on demand-based time-of-use rate schedules.

3. APS used the data for the NEM customer's entire load at the home — load served both by APS and the customer's rooftop solar system — as the starting point for cost allocation to develop the CP, NCP and Sum of Individual Max demand allocations, as well as the energy allocations.

4. APS then explicitly credited the customer for:

   - All their self-provided capacity based on a comparison to the APS-delivered customer load; and,

   - Their entire energy production, including both what the customer consumes on site and what is delivered from the NEM customer to the grid.

This approach fully credits residential solar customers for all cost savings resulting from the capacity and energy supplied to the grid by their rooftop solar systems. The result is that the COSS analysis only allocates capacity and energy costs to NEM customers based on what APS has to provide.[4]

Q. PLEASE EXPLAIN FURTHER HOW THIS APPROACH COMPENSATES NEM CUSTOMERS FULLY FOR THE BENEFITS THEY PROVIDE TO APS.

A. By comparing the entire load at the home to the remaining household load served by APS, we can determine the infrastructure which no longer needs to be provided by APS as a result of the solar system. While a solar installation will have a certain maximum-production capability, that capability will only be realized at mid-day and only on sunny days. The load information reveals what actually occurred when the customer was consuming energy in contrast with the solar production at the same time. The alignment between when a residential customer needs power and when the solar system operates is not significant in APS's service territory. APS's peak loads persist in the summer months beyond sunset, and the maximum peak load occurs closer to sunset than mid-day.

The appropriate level of compensation for offsetting demand-driven infrastructure costs should be based on how effective the NEM customer's solar system is at offsetting APS's peak loads. For example, the COSS indicates the appropriate level of production demand credit is no more than approximately 19% — when considering the class peak coincident with system peak and class NCP data — which are both relevant to and consistent with the production-cost-allocation method of AED.

[4] This addresses Question 14 from Chairman Little's December 2015 Letter regarding the consideration of fuel cost savings. In its COSS, APS directly credited DG customers for the fuel and energy value at APS's filed avoided cost. A detailed analysis that assesses the value at the time of production would yield lower results. In a resource planning context, the fuel savings will vary over the study period, however, in a COSS, the fuel savings is based on the test-year results.

Likewise, the energy compensation in a COSS should reflect the actual fuel costs that APS avoids when a solar customer consumes less energy. The method described above uses the filed avoided fuel costs for all kWh produced by the rooftop solar system, which is a conservative proxy for the actual cost saved by APS.[5]

Q. HOW DID THE COSS METHODOLOGY CONSIDER THE SEVEN CORE COST AND BENEFIT CATEGORIES IDENTIFIED BY CHAIRMAN LITTLE IN HIS DECEMBER 22, 2015 LETTER?

A. As Chairman Little's letter articulated in its suggested outcomes from this proceeding, APS reviewed the categories of cost and benefits in the process of developing this COSS methodology. The COSS methodology includes two of the three categories of cost articulated in Outcomes 4; it does not include system-integration costs. APS considered all of the benefits articulated in Outcomes 4, and recognized generation capacity and energy savings as described above. The COSS methodology did not include savings for transmission or distribution costs, nor did it include environmental or economic development benefits.

Q. DOES THE COSS METHODOLOGY INCLUDE VARIATIONS BASED ON SPECIFIC CUSTOMER LOCATION?

A. No. At present, there is no demonstrable effect on cost of service based on the location of a rooftop solar system. APS is presently studying the effect of rooftop solar on feeders in targeted locations as a part of its Solar Partners Program.[6]

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[5] APS Witness Albert describes a detailed methodology for establishing a value of solar that compares the market value of the energy at the time it is produced. Such an analysis would likely produce a different value of energy based on market prices than the filed APS avoided cost.

[6] Decision No. 74878 (December 23, 2014).

Q. DOES THE COSS METHODOLOGY INCLUDE TRANSMISSION OR DISTRIBUTION SAVINGS?

A. No. Although some have speculated on this topic, the 2014 data make clear that customers with rooftop solar which was installed without regard to location did not cause any transmission or distribution savings.

Q. DOES THE COSS METHODOLOGY INCORPORATE ENVIRONMENTAL AND ECONOMIC DEVELOPMENT BENEFITS?

The COSS methodology does not consider environmental or economic development benefits because they are not part of the cost to serve customers. They are intangible and unquantifiable values. If they are to be considered at all, they are more appropriately considered in a resource planning context when comparing resource alternatives. There, one can assess which resource provides the most environmental and economic benefit and use that assessment in resource planning decisions as appropriate. But with regard to developing a COSS methodology — in which the actual costs incurred to provide electric service are allocated to customers on the basis of cost causation — intangible and unquantifiable values should not be included.

Q. DOES THE 19% DEMAND CREDIT PROVIDED TO DISTRIBUTED SOLAR IN YOUR COSS MEAN THAT RESIDENTIAL ROOFTOP SOLAR INSTALLATIONS HELP DEFER FUTURE APS POWER PLANT ADDITIONS?

A. The production-demand infrastructure credit today is at most 19%, which is the appropriate level of credit that results from the COSS. In the future, APS's peak demand will slowly move later in the day. 2014 was the first year APS saw summer peak demands occur in the hour ending at 6:00 p.m. As the peak continues to shift to a later time, the production-demand infrastructure credit value will further decrease. APS witness Brad Albert discusses this topic in detail.

Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COSS.

A. APS makes sales to parties that are not traditional APS retail customers such as sales to Rate Schedule E-36 customers for station service power to large generation plants owned by other parties. To be certain that all the benefits of such transactions flow through to retail customers, the revenues derived from these transactions, which more than cover the incremental costs associated with producing or acquiring the required energy, are allocated to all customers. Thus, the entire margin or profit that APS realizes from these non-retail transactions is attributed to each class through the revenue credit, which benefits all customers by lowering the amount of their overall revenue requirements.

APS also treats non-firm, short-term transactions and a number of other small items, such as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service Revenues, and Other Electric Revenues, as revenue credits.

Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES?

A. Yes. Various adjustors, surcharges, regulatory assessments, sales/transaction privilege taxes, and franchise fees are charged outside of base rates. The COSS only addresses the base rate portion of the cost to serve. The revenues from adjustors are a revenue credit to the COSS revenue requirement. When the revenue from adjustors is included in the overall calculation, an additional shortfall from solar customers is included in cost recovery. For a full determination of costs that will otherwise be shifted to customers without solar, this shortfall should be added to the COSS results.

Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND PERCENT OF COST TO SERVE BASED ON THE 2014 TEST YEAR?

A. Yes. In addition to establishing the Production, Transmission, and Distribution functional allocations and the Demand, Energy, and Customer classifications for each class of retail customers, the percentage of cost to serve for each class under Test Year rates appears in the Summary Schedules.

Q. BASED ON THE RESULTS OF YOUR 2014 TEST YEAR COST OF SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?

A. The Summary and COSS Schedules plainly show disparities in the ratio of the allocated cost for APS to actually provide service and what customer classes and sub-classes pay for the services APS provides. The residential class contributes less toward the cost to serve than does the general service class. Specifically, under current rates, the revenue from the residential class covers approximately 87% of the cost to serve while the general service class covers 116% of the cost to serve. This difference has been recognized in, and results from, past decisions in APS rate cases, and is true for many utilities in this country.

Within the residential class, there is further disparity within the sub-classes:

- NEM customers on energy-based rates cover only approximately 36% of the cost to serve;
- NEM customers on demand rates cover around 72% of the cost to serve; and,
- Other non-solar residential customer sub-classes cover a range from 86% to 91% of the cost to serve.

Unlike the differences between residential and general service classes, the difference in cost-of-service contributions by residential customers with and without solar does not stem from express Commission direction.

Q. BASED ON THE PERCENTAGE OF COST TO SERVE RESULTS, WHAT IS THE COST SHIFT THAT WILL OCCUR UNDER CURRENT RATE STRUCTURES?

A. Absent affirmative action by the Commission, responsibility to pay the cost of service not paid by residential customers with solar will be shifted to residential customers without solar in APS's next rate case. This is commonly referred to as the "cost shift," and was recognized by the Commission in Paragraph 49 of Decision No. 74202 (2013). In fact, utility commissions across the country are beginning to explicitly recognize and acknowledge the need to address the cost shift. Most recently, the PUCN found that NEM customers do shift costs and quantified that cost shift for NV Energy customers:

> On average, the resulting shift in cost responsibility is approximately \$623 and \$471 for each single family residential NEM ratepayer annually for NPC and SPPC, respectively. The magnitude of this cost shift is unreasonable.[7]

In APS's territory, the magnitude of the cost shift is even higher. By paying 36% of the cost to serve instead of the residential average of 87%, each NEM customer on an energy-based rate avoids \$67 per month and each NEM customer on a demand-based rate avoids \$29 per month.

Whereas the annual cost shift for the two utilities in Nevada is approximately \$471 and \$623 for solar customers on energy-based rates, the annual cost shift in APS's territory is approximately \$804. This represents the total amount shifted, which includes both the

[7] Modified Final Order at Paragraph 88. In the Order, NPC refers to Nevada Power Company and SPPC refers to Sierra Pacific Power Company.

amount in base rates determined by the COSS and the amount from APS's adjustor mechanisms.

Q. BASED ON THE COST SHIFT OF $804 ANNUALLY PER SOLAR CUSTOMER, WHAT IS THE TOTAL COST SHIFT OVER THE LIFE OF THE ROOFTOP SOLAR SYSTEMS?

A. Assuming the cost shift is grandfathered, the 27,078 NEM customers on an energy rate and the 1,176 NEM customers on a demand rate at the end of 2014 will increase the revenue to be collected from all other residential customers by approximately $22 million per year. Over the typical 20 year life of a rooftop solar system, the total amount shifted to customers without rooftop solar will be approximately $440 million. In addition, APS added 9,044 new residential rooftop solar customers in 2015. For each year that this pace continues, the annual cost shift will grow by more than $7 million and the 20-year cost shift will grow by more than $144 million. In other words, assuming all DG systems installed through 2015 are grandfathered, the annual cost shift is $29 million, and the 20-year cost shift will be over $580 million.[8]

Q. IS THE COST-SHIFT CAUSED BY THE PREDOMINANT VARIABLE KWH PRICE SIGNALS IN EXISTING RATE DESIGN?

A. Yes. In the COSS, costs are allocated based on the true-cost drivers. APS's infrastructure costs are predominantly driven by capacity needs — which do not vary with kWh consumption. As previously shown in Figures 1 and 2, the residential NEM customer significantly changes their energy profile by taking less energy during the day. This customer does not, however, significantly change their demand profile; APS must still meet the customer's demand later after the sun has set, but when the customer is

[8] In APS's application for the Grid Access Charge filed on April 2, 2015 in Docket No. E-01345A-13-0248, APS indicated a cost shift of over $800M over 20 years if all systems installed through mid-2017 were grandfathered. Using this same approach and with updated data the number would be approximately $804 million.

still significantly relying on the grid. As a result, APS must still incur the capacity-related production, transmission and distribution costs needed to provide service to the NEM customer. The mismatch in the most-common residential rates used by NEM customers results from the fact the price to the customer is overwhelmingly based on kWh energy, rather than capacity, which is offset to a much smaller degree. Said another way, infrastructure, and the related costs are a function of demand, rather than energy.

Q. ARE THERE OTHER POTENTIAL COST SHIFTS IN RESIDENTIAL RATES?

A. Yes. As discussed previously, APS's residential rates in total are lower today than the COSS's calculated cost to serve, and commercial rates are correspondingly higher. This difference has been in existence in APS's service territory for a long time and is not uncommon within the electric utility industry. Limited-income discounts are another specific cost shift that have been purposefully established.

Q. HAVE OTHER POTENTIAL COST SHIFTS BEEN DISCUSSED IN OTHER DOCKETS RELATED TO NET METERING?

A. Yes. Some have suggested there is a subsidy related to coal or nuclear generation resulting from historical tax treatment or, for example, the Price-Anderson Act that benefitted the nuclear generation industry. However, any cost advantage APS's generation fleet enjoys inures to the benefit of all APS customers; there is no cost shift from one customer group to another. In addition, some have alleged:

1. Customers who engage in energy efficiency are no different than customers who adopt solar generation;

2. Subsidies exist when a small apartment pays less than the average monthly customer cost for service;

3. Seasonal customers do not pay their fair share of grid support costs;

4. Customers with gas appliances in their homes do not pay their fair share of costs; and,

5. Empty nesters, customers who travel, or homes with no one at home during the day all contribute less to the residential cost of service than they should.

Q. IS THERE ANY FACTUAL BASIS TO THESE ASSERTIONS?

A. No. These assertions are unsupported by the facts. Most of the assertions merely reflect the normal variations in energy usage that occur within a rate sub-class, where the variations are not significant enough to merit separate sub-class analysis. For example, the empty nesters, customers who travel, and homes with no one home during the day would fall into this group. Typical residential rooftop solar adoption stands in deep contrast. The typical solar customer will reduce their energy purchases by 70% or more, but will only reduce their kW demand during peak periods by 19% — meaning they will have a monthly energy consumption from APS equal to a small apartment, but with an infrastructure service requirement of a medium to large house.

Q. HOW IS ENERGY EFFICIENCY DIFFERENT THAN ROOFTOP SOLAR?

The customer who engages in multiple energy-efficiency programs retains a load shape that is very similar to the average APS residential customer. The solar customer does not. The rooftop solar customers' energy profile is not the same as a customer who aggressively pursues energy efficiency. While energy-efficiency measures under energy-only rate designs can shift costs too, the cost shift is significantly different from solar.

Energy efficiency typically reduces energy consumption by 5% to 10%, compared with a 70% reduction with rooftop solar. Under an energy-based rate, where the amount of energy consumed determines the amount contributed to grid costs, the difference is dramatic. In addition, energy-efficiency measures do not require APS to provide backup generation. If an efficient air conditioner does not turn on, the customer's load goes away — the air conditioner is not working. If a solar system suddenly stops producing energy, however, the customer's load must just as suddenly be served by utility generation.

Finally, virtually everyone can participate in energy efficiency, not just the owners of single-family residences with particular roof characteristics. Although energy efficiency shifts costs to other customers, those other customers can also participate in energy efficiency, mitigating any resulting inequity.

Q. DOES APS HAVE ANY INFORMATION ON THE COST TO SERVE SMALL APARTMENT CUSTOMERS?

A. Yes. While APS does not create a separate sub-class for apartments, APS has conducted a review of whether customers living in apartments are paying an appropriate share of the cost to serve. Based on this analysis, customers who live in apartments are paying about 88% of the cost to serve. This results from a lower capacity requirement in addition to the lower energy use.

For example, a typical residential rooftop solar customer has a demand above 7 kW during peak periods. By contrast, a typical apartment customer uses the same energy as that 7 kW solar customer, but only has a peak demand of approximately 4 kW.

Q. HAS APS REVIEWED THE COST TO SERVE SEASONAL CUSTOMERS?

A. Yes. For APS, seasonal customers are largely winter visitors that are residents in Arizona during the milder winter season and reside elsewhere during the summer months. Because winter visitors are not in Arizona in the summer, the time of year that drives APS's system costs, winter visitors have a relatively low bill, but still pay over 100% of the cost to serve, in contrast to the typical residential customer that pays 87% of the cost to serve.

Q. DOES APS HAVE ANY INFORMATION ON THE COST TO SERVE CUSTOMERS THAT ALSO HAVE NATURAL GAS APPLIANCES?

A. Yes. APS has a sample of customers that have gas appliances and performed an analysis of the cost to serve these customers. This customer group pays 82% of the cost to serve. While this is a lower percentage of the cost to serve than the typical APS residential customer who pays 87%, it is still higher than even the residential solar customers on APS's existing residential demand rates that pay 72%. See Figures 4 and 5 for a comparison of typical solar and non-solar customer's daily load shapes for a summer and winter day, contrasted with the load shapes for customers that 1) adopt energy efficiency; 2) live in an apartment; 3) a winter visitor; and 4) live in a dual fuel home.

Figure 4.

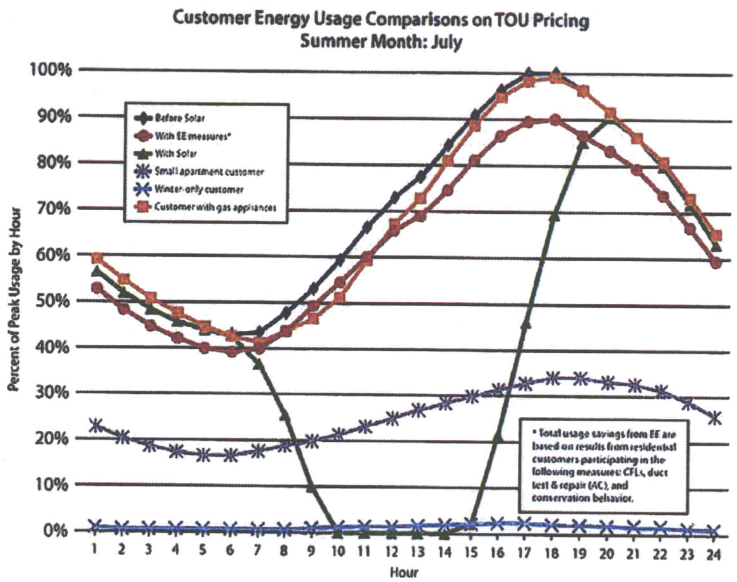
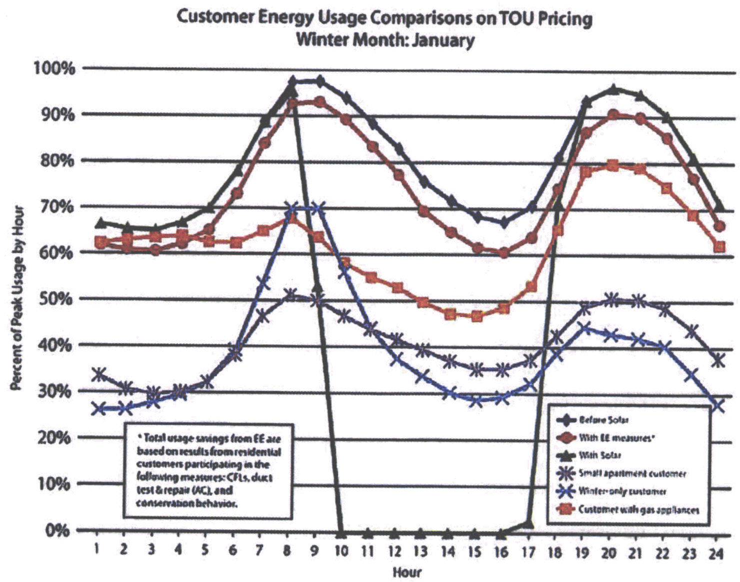


Figure 5.



Q. ARE THERE RESIDENTIAL RATE DESIGN ALTERNATIVES THAT COULD ADDRESS THE FACT THAT SOLAR CUSTOMERS ARE PAYING A MUCH LOWER PORTION OF THE COST TO PROVIDE SERVICE THAN NON-SOLAR RESIDENTIAL CUSTOMERS?

A. Yes. Rate designs that are better aligned with cost drivers will do a better job of recovering the cost of providing electric service from the customers driving the cost. For example, a residential demand rate would provide better price information to the customer to manage demand in addition to their energy consumption. A demand rate that focuses on the on-peak time period further enhances this price information.

A demand-rate approach sends price information that will assist a customer in determining system orientation that is superior to a kWh price alone. For example, if the customer orients their system to the west, the system will produce later in the day, helping to offset the customer's load later into the on-peak period. Orienting the system to the south will maximize energy production, but most of the production will occur at mid-day. A demand rate structure would provide price information that properly values both capacity and energy. Today's current rate design does not.[9]

V. RESPONSE TO CHAIRMAN LITTLE'S LETTER

Q. CHAIRMAN LITTLE REQUESTED PARTIES' INPUT ON THE APPROPRIATE METHODOLOGY TO USE IN FUTURE RATE CASE PROCEEDINGS. GIVEN THIS CONTRAST BETWEEN A COST OF SERVICE STUDY AND A VALUE OF SOLAR STUDY, PLEASE PROVIDE APS'S PERSPECTIVE ON THIS.

A. APS firmly believes the COSS should be used in the rate-setting process and a value of solar analysis is appropriate to consider in a resource planning context. The two analyses are fundamentally different for the reasons stated above.

APS further believes its cost allocation methods in the COSS in this docket, where solar customers have been modeled as a separate customer rate class, should be the method adopted by the Commission with respect to future rate-case proceedings. This method provides definitive results relying on actual data, and removes the current ambiguity regarding the degree to which customers with solar contribute to the cost to provide them electrical service.

I note, however, that in addition to resource planning, a value of solar study can still inform policies regarding distributed solar. For instance, compensation to a solar customer for net energy exported to the grid is distinct from the design of that customer's rate as established through a COSS. The cost of service should determine the manner in which a customer contributes to the grid's fixed, variable, and demand-related costs. But the Commission may determine that it is appropriate to establish a value for solar, and that non-solar customers should pay solar customers that value for solar

[9] See Chairman Little's Question 5.

energy supplied to the grid from rooftop solar systems. And it is within the Commission's purview to decide that non-solar customers should pay more than cost for this solar energy (in other words, subsidize solar). APS witness Albert discusses this issue in more detail, and provides a range of methodologies that the Commission could use to develop a value of solar.

Q. PLEASE EXPLAIN FURTHER WHY RATES SHOULD NOT BE SET BASED ON POTENTIAL FUTURE BENEFITS OR "VALUE OF SOLAR"?

A. Rates have been and are based on cost, not on potential future benefits. A COSS, using actual, verifiable data, is used to set rates. Using a COSS to set rates protects customers by ensuring that customers pay only for actual costs that they cause. In a COSS, the tangible benefits in the study period of rooftop solar are included.

A value of solar analysis does not look at actual costs, and is fundamentally different than a COSS. It involves predicting the marginal benefits of solar over the next 20 or 25 years, and often includes both operational and societal benefits These analyses then attempt to monetize the hypothetical values to arrive at a "value of solar," and then net those future unknown benefits against actual costs established in a COSS. I note that the adjusted cost of grid-scale solar method to determine the value of solar, as discussed by APS witness Albert, does not share these same drawbacks.

The structure of a value of solar analysis is similar to the long-run marginal cost analyses traditionally used by resource planners in deciding the amount and type of resource to procure in light of predicted resource needs. There are important differences, however, including:

- Resource planners focus on estimating impacts to future operating and capital costs of the utility, not societal benefits; and,

- Resource plans are continually updated so that by the time a decision must be made about procuring resources, the relevant time period for the estimates is only a few years in the future and the best available information is available.

Long-run marginal cost studies are not COSS and are not used to establish rates — not in Arizona, nor in any other retail jurisdiction of which I am aware. A small handful of states, such as Nevada, use marginal cost studies to determine allocation factors, which are then applied to embedded costs in the rate making process. States with future test periods project costs into the future, but only as far as the future test period to set rates, and have carefully crafted procedures to ensure that the resulting rates reflect actual costs.

A COSS determines how to recover the cost of providing service today based on costs actually incurred. Although rate making and resource planning are related activities, they are two separate analyses used specifically for different purposes. A valid Value of Solar study is a resource planning exercise and should not be conflated with a cost of service analysis used for ratemaking.

As stated above, a COSS includes the tangible benefits. Indeed, netting the hypothetical benefits of solar against known and established costs and benefits can create significant problems for customers. The result of this netting is that customers without solar pay more — customers with solar contribute less to fixed costs than they should, as established by a COSS, under the assumption that the hypothetical benefits will equitably resolve cost responsibility at some point in the future. The problem arises because these unpaid fixed costs are shifted to customers without rooftop solar, who pay higher rates as a result. But what if those customers without rooftop solar move before the projected cost savings occur? Or what happens if the hypothetical benefits do not materialize? In those circumstances, those customers without rooftop solar will have been paying higher rates in anticipation of future cost savings that they never benefit from, or never even occur in the first place.

In Nevada, the PUCN recently opined on this very topic and rejected the rooftop solar industry's argument that speculative value should offset rates based on a historical test year:

> Parties' proposals to weigh speculative, unquantified future benefits/values of NEM to offset current, known costs are rejected. These proposals conflate two separate and distinct regulatory processes: (1) the rate setting process, and (2) the resource planning process. When determining the rates that ratepayers pay for electric service, the revenue requirement is allocated to ratepayer classes based on the actual, measureable costs of providing service. Future benefits/values of NEM should be evaluated in the resource planning process. Rates are based on marginal (internal utility) costs and do not reflect external benefits or costs for any ratepayer class. External societal costs and benefits are not included in the cost recovery that NV Energy's rates provide for any class. No exception should be made for NEM ratepayers.[10]

The Public Service Commission of Utah arrived at the same conclusion, rejecting the rooftop solar industry's proposal to:

> . . . adopt a framework that treats customer-owned and controlled equipment as a system resource, requiring speculation about the cost impacts of these customer owned and controlled assets decades into the future and assigning a present value to impacts that, even if they come to fruition, are not projected to materialize for many years.[11]

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[10] Modified Final Order at Paragraph 85.
[11] Order (November 10, 2015) in Public Service Commission of Utah Docket No. 14-035-114 at p. 14.

Q. ARE THERE ANY OTHER ITEMS RAISED BY CHAIRMAN LITTLE'S LETTER THAT YOU WANT TO ADDRESS?

A. Yes. Chairman Little's Question 1 asks whether the value and cost of solar was considered in the development of the current net metering tariffs. In adopting the revised 2005 federal PURPA standards, the Commission did identify potential benefits that DG might provide.[12] The Commission also references concerned expressed by APS and other utilities that "customers taking service under net metering rates do not pay the full cost of the transmission and distribution system."[13] The Commission decision, however, did not resolve either the benefits or costs of net metering.

A year later, the Commission created the net metering rules in Decision No. 70567. Similar to the 2007 decision adopting the 2005 PURPA standards, the Commission decision adopting the net metering rules did not resolve the issue of benefits and costs in relation to net metering. In fact, Decision No. 70567 does not appear to address benefits and costs at all.[14]

VI. CONCLUSION

Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO COST OF SERVICE MATTERS IN THIS PROCEEDING?

A. The 2014 test year COSS demonstrates that it is appropriate to consider NEM customers as a unique customer sub-class, given their unique load characteristics and their class size. With NEM customers segmented into unique energy- and demand-rate sub-classes within the residential class of service, the COSS reveals that NEM customers on an energy-based rate only pay about 36% of the cost to serve and NEM customers on a

[12] Decision No. 69877 at paragraphs 7-8 (August 28, 2007).
[13] Decision No. 69877 at paragraph 11.
[14] Decision No. 70567 (October 28, 2008).

demand rate only pay approximately 72% of the cost to serve. Non-solar residential customers pay between 86% and 91% of the cost to serve. Further, the COSS effectively illustrates that the base rate cost shift from residential NEM customers to non-solar residential customers is real and significant, equal to $67 per customer per month on an energy rate and $29 on a demand rate. This affirms the Commission's finding that the cost shift resulting from NEM under current APS residential rate design exists.

Because rates are based on historical test year data, the Commission should adopt the Company's COSS methodology as set forth in this docket. Further, the Commission should find and conclude as a policy matter that Value of Solar methodologies will not be used in setting rates. Finally, it would be appropriate for the Commission to treat residential rooftop solar customers as a unique sub-class in cost of service studies and in the design of residential rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment LRS-1DR

Statement of Qualifications

Leland R. Snook

Leland R. Snook is Arizona Public Service Company's Director, Rates and Rate Strategy. Mr. Snook's areas of expertise include development and analysis of electric utility revenue requirements, modeling of cost of service, rate schedule design, embedded and marginal cost analysis and formulation of utility service policies. Mr. Snook has previously testified before the Arizona Corporation Commission on customer contracts, cost recovery mechanisms, fair value of utility property, rate schedules and pricing. Mr. Snook holds a Bachelor of Science Degree in Electrical Engineering from Texas Tech University and is a registered professional electrical engineer in the state of Arizona.

Mr. Snook has held his current position at Arizona Public Service Company for approximately seven years. Prior to assuming that position, he served as the Director of Federal Regulation for APS. Before joining APS, Mr. Snook had a 22-year career with Tucson Electric Power Company, where he served in various professional and leadership roles.

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *Present Rates*
Rates of Return by Customer Classification
Test Year Ending December 31, 2014
($000)

					Total ACC Jurisdiction				
		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	2,896,934	2,828,140	68,794	1,437,422	1,332,635	29,641	19,973	8,469
1.b.	Other Revenues	592,011	565,177	26,834	311,955	242,388	7,668	2,475	691
2.	Expenses	2,669,476	2,702,420 (a)	(32,944)	1,506,611 (a)	1,142,678 (a)	31,168 (a)	16,621 (a)	5,342 (a)
3.	Operating Income Before Income Taxes	819,469	690,897	128,572	242,766	432,345	6141	5,827	3,818
4.	Income Taxes	249,269	210,201	39,068	56,372	149,039	1,960	1,618	1,212
5.	Net Operating Income	570,200	480,696	89,504	186,394	283,306	4,181	4,209	2,606
6.	Rate Base	7,378,528	6,216,598 (b)	1,161,930	3,979,550 (b)	2,093,716 (b)	45,844 (b)	68,320 (b)	29,169 (b)
7.	Rate of Return	7.73%	7.73%	7.70%	4.68%	13.53%	9.12%	6.15%	8.93%

Supporting Schedules:
(a) Schedule 3
(b) Schedule 2

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Allocation to Classes of Service
Total Rate Base
Test Year Ending December 31, 2014
($000)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %
		(A)	(a)	(a)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1.	Residential	1,771,780	0	0	212,713	236,772	128,701	818,738	319,305	3,488,009	63.68%	47,999	50.70%
2.	General Service	1,109,199	0	0	130,125	144,842	0	415,181	118,813	1,918,160	35.02%	44,804	47.33%
3.	Water Pumping	31,708	0	0	3,644	4,057	0	0	1,187	40,596	0.74%	1,256	1.33%
4.	Street Lighting	14,358	0	0	1,670	1,859	615	5,999	1,525	26,027	0.48%	523	0.55%
5.	Dusk to Dawn	2,393	0	0	268	299	99	963	245	4,267	0.08%	84	0.09%
6.	Total	2,929,438 (a)	0	0	348,421 (a)	387,829 (a)	129,414 (a)	1,240,882 (a)	441,075 (a)	5,477,059	100.00%	94,666	100.00%

Line No.	Class of Service	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(a)	(a)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
7.	Residential	(101,117)	45,335	105,238	186,778	78,093	0	0	6,894	15,504	336,723	77.55%
8.	General Service	(72,604)	6,250	42,614	42,534	9,521	0	0	841	1,890	31,047	7.15%
9.	Water Pumping	(893)	586	0	1,362	110	0	0	10	22	1,197	0.28%
10.	Street Lighting	(674)	0	0	0	76	0	41,180	7	15	40,605	9.35%
11.	Dusk to Dawn	(212)	0	0	0	622	24,042	0	55	123	24,630	5.67%
12.	Total	(175,500) (a)	52,171 (a)	147,852 (a)	230,674 (a)	88,422 (a)	24,042 (a)	41,180 (a)	7,806 (a)	17,555 (a)	434,201	100.00%

Line No.	Class of Service	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)	TOTAL ACC JURIS. %
		(a)	(D)	(E)	(F)
13.	Residential	106,817	50.70%	3,979,550	64.01%
14.	General Service	99,708	47.33%	2,093,716	33.68%
15.	Water Pumping	2,795	1.33%	45,844	0.74%
16.	Street Lighting	1,165	0.55%	68,320	1.10%
17.	Dusk to Dawn	188	0.09%	29,169	0.47%
18.		210,672 (a)	100.00%	6,216,598	100.00%

Supporting Schedules
(a Schedule 4

Recap Schedules:
Schedule 1

ARIZONA PUBLIC SERVICE COMPANY
Expense Allocation to Classes of Service
Operating Expenses Excluding Income Taxes
Test Year Ending December 31, 2014
($000)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1.	Residential	360,390	0	154,275	(11,756)	35,312	18,595	72,604	25,487	654,908	60.24%	624,968	48.64%
2.	General Service	241,798	0	90,363	14,155	21,602	0	36,818	9,507	414,243	38.10%	636,159	49.51%
3.	Water Pumping	6,952	0	3,825	396	605	0	0	91	11,870	1.09%	16,488	1.28%
4.	Street Lighting	2,926	0	1,052	182	277	89	532	122	5,180	0.48%	6,267	0.49%
5.	Dusk to Dawn	581	0	168	29	45	14	85	20	942	0.09%	1,087	0.08%
6.	Total	612,647 (a)	0 (a)	249,684 (a)	3,007 (a)	57,841 (a)	18,698 (a)	110,039 (a)	35,227 (a)	1,087,143	100.00%	1,284,970	100.00%

Line No.	Class of Service	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
7.	Residential	6,575	9,379	51,616	75,400	0	0	26,437	14,566	183,974	74.79%
8.	General Service	907	3,798	11,754	9,193	0	0	24,934	1,776	52,361	21.29%
9.	Water Pumping	85	0	376	106	0	0	1,103	20	1,691	0.69%
10.	Street Lighting	0	0	0	74	0	4,384	236	14	4,707	1.91%
11.	Dusk to Dawn	0	0	0	600	2,453	0	70	116	3,239	1.32%
12.	Total	7,567 (a)	13,177 (a)	63,747 (a)	85,373 (a)	2,453 (a)	4,384 (a)	52,780 (a)	16,493 (a)	245,972	100.00%

Line No.	Class of Service	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (c)	TOTAL ACC JURIS. %
		(C)	(D)	(E)	(F)
13.	Residential	42,761	50.70%	1,506,611	55.75%
14.	General Service	39,915	47.33%	1,142,678	42.28%
15.	Water Pumping	1,119	1.33%	31,168	1.15%
16.	Street Lighting	466	0.55%	16,621	0.62%
17.	Dusk to Dawn	75	0.09%	5,342	0.20%
18.	Total	84,335 (a)	100.00%	2,702,420	100.00%

Supporting Schedules:
(a) Schedule 5

Recap Schedules:
Schedule 1

ARIZONA PUBLIC SERVICE COMPANY
Distribution of Rate Base by Function
Total Rate Base
Test Year Ending December 31, 2014
($000)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	2,929,438	0	0	0	0	0	0	0	2,929,438	53.49%
2.	Transmission Substation	0	0	0	0	0	0	0	0	0	0.00%
3.	Transmission Lines	0	0	0	0	0	0	0	0	0	0.00%
4.	Distribution Substation	0	0	0	348,421	0	0	0	0	348,421	6.36%
5.	Distribution OH Primary	0	0	0	0	387,829	0	0	0	387,829	7.08%
6.	Distribution OH Secondary	0	0	0	0	0	129,414	0	0	129,414	2.36%
7.	Distribution UG Lines	0	0	0	0	0	0	1,240,882	0	1,240,882	22.66%
8.	Distribution Line TXFs	0	0	0	0	0	0	0	441,075	441,075	8.05%
9.	Total	2,929,438	0	0	348,421	387,829	129,414	1,240,882	441,075	5,477,059	100.00%

Line No.	Plant Classification	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
10.	Cust. Advances & Deposit	(175,500)	0	0	0	0	0	0	0	0	(175,500)	-40.42%
11.	Distribution OH Services	0	52,171	0	0	0	0	0	0	0	52,171	12.02%
12.	Distribution UG Services	0	0	147,852	0	0	0	0	0	0	147,852	34.05%
13.	Distribution Meters	0	0	0	230,674	0	0	0	0	0	230,674	53.13%
14.	Customer Accounts	0	0	0	0	88,422	0	0	0	0	88,422	20.36%
15.	Dusk to Dawn	0	0	0	0	0	24,042	0	0	0	24,042	5.54%
16.	Street Lighting	0	0	0	0	0	0	41,180	0	0	41,180	9.48%
17.	Customer Service & Info	0	0	0	0	0	0	0	7,806	0	7,806	1.80%
18.	Sales	0	0	0	0	0	0	0	0	17,555	17,555	4.04%
19.	Total	(175,500)	52,171	147,852	230,674	88,422	24,042	41,180	7,806	17,555	434,201	100.00%

Line No.	Plant Classification	Total Energy	Total Energy %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)
		(A)	(B)	(E)	(F)	(G)
20.	Production - Energy	94,666	100.00%			
21.	Regulatory Assets					
22.	System Benefits			210,672	100.00%	
23.	TOTAL ACC					6,216,598

Supporting Schedules:
N/A

Recap Schedules:
(a) Schedule 2

ARIZONA PUBLIC SERVICE COMPANY
Distribution of Expenses by Function
Operating Expenses Excluding Income Taxes
Test Year Ending December 31, 2014
($000)

Line No.	Plant Classification	Production - Demand (A)	Transmission Substation (B)	Transmission Lines (C)	Distribution Substation (D)	Distribution OH Primary (E)	Distribution OH Secondary (F)	Distribution UG Lines (G)	Distribution Line TXFs (H)	Total Demand (I)	Total Demand % (J)
1.	Production - Demand	612,647	0	0	0	0	0	0	0	612,647	56.35%
2.	Transmission Substation	0	0	0	0	0	0	0	0	0	0.00%
3.	Transmission Lines	0	0	249,684	0	0	0	0	0	249,684	22.97%
4.	Distribution Substation	0	0	0	3,007	0	0	0	0	3,007	0.28%
5.	Distribution OH Primary	0	0	0	0	57,841	0	0	0	57,841	5.32%
6.	Distribution OH Secondary	0	0	0	0	0	18,698	0	0	18,698	1.72%
7.	Distribution UG Lines	0	0	0	0	0	0	110,039	0	110,039	10.12%
8.	Distribution Line TXFs	0	0	0	0	0	0	0	35,227	35,227	3.24%
9.	Total	612,647	0	249,684	3,007	57,841	18,698	110,039	35,227	1,087,143	100.00%

Line No.	Plant Classification	Distribution OH Services (A)	Distribution UG Services (B)	Distribution Meters (C)	Customer Accounts (D)	Dusk to Dawn (E)	Street Lighting (F)	Customer Service & Info (G)	Sales (H)	Total Customer (I)	Total Customer % (J)
10.	Distribution OH Services	7,567	0	0	0	0	0	0	0	7,567	3.08%
11.	Distribution UG Services	0	13,177	0	0	0	0	0	0	13,177	5.36%
12.	Distribution Meters	0	0	63,747	0	0	0	0	0	63,747	25.92%
13.	Customer Accounts	0	0	0	85,373	0	0	0	0	85,373	34.71%
14.	Dusk to Dawn	0	0	0	0	2,453	0	0	0	2,453	1.00%
15.	Street Lighting	0	0	0	0	0	4,384	0	0	4,384	1.78%
16.	Customer Service & Info	0	0	0	0	0	0	52,780	0	52,780	21.46%
17.	Sales	0	0	0	0	0	0	0	16,493	16,493	6.71%
18.	Total	7,567	13,177	63,747	85,373	2,453	4,384	52,780	16,493	245,972	100.00%

Line No.	Plant Classification	Total Production - Energy (A)	Total Energy % (B)	Total System Benefits (E)	Total System Benefits % (F)	TOTAL ACC JURIS. (a) (G)
19.	Production - Energy	1,284,970	100.00%			
20.	Regulatory Assets					
21.	System Benefits			84,335	100.00%	
22.	TOTAL ACC					2,702,420

Supporting Schedules:
N/A

Recap Schedules:
(a) Schedule 3

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	Total Company	Total ACC Jurisdiction	All Other	Total Retail	Residential	General Service	E-38,221 (Water Pumping)	Street Lighting	Dusk to Dawn
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	100.00%	97.93%	2.07%	97.93%	59.23%	37.08%	1.06%	0.48%	0.08%
	Production Demand	100.00%	97.93%	2.07%	97.93%	59.23%	37.08%	1.06%	0.48%	0.08%
2. DEMPROD6	Specific Assignment	100	0	100	0	0	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	100	0	100	0	0	0	0	0	0
	Transmission Substation	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	100	0	100	0	0	0	0	0	0
	Transmission Lines	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	7,289,745	7,289,745	0	7,289,745	4,450,431	2,722,500	76,251	34,950	5,613
	Distribution Substation	99.98%	99.98%	0.00%	99.98%	61.04%	37.33%	1.05%	0.48%	0.08%
6. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	7,105,017	7,105,017	0	7,105,017	4,337,653	2,653,510	74,319	34,064	5,471
	Distribution OH Primary Lines	99.98%	99.98%	0.00%	99.98%	61.04%	37.33%	1.05%	0.48%	0.08%
7. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	6,946,854	6,946,854	0	6,946,854	6,908,554	0	0	33,000	5,300
	Distribution OH Secondary Lines	100.00%	100.00%	0.00%	100.00%	99.44%	0.00%	0.00%	0.48%	0.08%
8. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	7,030,698	7,030,698	0	7,030,698	4,337,653	2,653,510	0	34,064	5,471
	Distribution UG Primary Lines	99.97%	99.97%	0.00%	99.97%	61.66%	37.75%	0.00%	0.48%	0.08%
9. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	6,946,854	6,946,854	0	6,946,854	6,908,554	0	0	33,000	5,300
	Distribution UG Secondary Lines	100.00%	100.00%	0.00%	100.00%	99.44%	0.00%	0.00%	0.48%	0.08%
10. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	9,224,567	9,224,567	0	9,224,567	7,039,817	2,021,771	123,951	33,627	5,401
	Distribution OH Line Transformers	99.99%	99.99%	0.00%	99.99%	76.30%	21.93%	1.34%	0.36%	0.06%
11. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	9,858,352	9,858,352	0	9,858,352	7,039,817	2,779,507	0	33,627	5,401
	Distribution UG Line Transformers	99.99%	99.99%	0.00%	99.99%	71.39%	28.21%	0.00%	0.34%	0.05%
12. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	301,428	301,428	0	301,428	261,928	36,113	3,387	0	0
	Distribution OH Services	100.00%	100.00%	0.00%	100.00%	86.90%	11.98%	1.12%	0.00%	0.00%
13. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	1,099,867	1,099,867	0	1,099,867	782,860	317,007	0	0	0
	Distribution UG Services	100.00%	100.00%	0.00%	100.00%	71.16%	28.84%	0.00%	0.00%	0.00%
14. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	7,105,017	7,105,017	0	7,105,017	4,337,653	2,653,510	74,319	34,064	5,471
	Distribution Rents	99.98%	99.98%	0.00%	99.98%	61.04%	37.33%	1.05%	0.48%	0.08%
15. ENERGY1	Customer Class Energy @ Generation (MWH)	28,439,817	27,821,398	618,419	27,821,398	14,106,290	13,167,438	369,052	153,848	24,770
	Production - Energy	99.98%	97.81%	2.17%	97.81%	49.60%	46.28%	1.30%	0.54%	0.09%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	Total Company	Total ACC Jurisdiction	All Other	Total Retail	Residential	General Service	E-38,221 (Water Pumping)	Street Lighting	Dusk to Dawn
16. ENERGY2	Weighted Hourly Energy Allocator @ Generation	100.00%	97.83%	2.17%	97.83%	49.85%	46.13%	1.28%	0.49%	0.08%
	Production - Energy (Fuel and Purchased Power)	100.00%	97.83%	2.17%	97.83%	49.85%	46.13%	1.28%	0.49%	0.08%
17. CUST370	Weighted Costs for Distribution Meters ($)	1,299,475	1,290,334	9,140	1,290,334	1,044,789	237,926	7,620	0	0
	Distribution Meters	100.00%	99.30%	0.70%	99.30%	80.40%	18.31%	0.59%	0.00%	0.00%
18. CUST371	Dusk to Dawn Customer Class Specific	1	1	0	1	0	0	0	0	1
	Dusk to Dawn	100.00%	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
19. CUST373	Street Lighting Customer Class Specific	1	1	0	1	0	0	0	1	0
	Street Lighting	100.00%	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%
20. CUSTNUM	Number of Customer Accounts	1,184,446	1,182,977	1,469	1,182,977	1,044,789	127,379	1,467	1,023	8,319
	Customer Accounts	100.00%	99.88%	0.12%	99.88%	88.21%	10.76%	0.12%	0.09%	0.70%
21. CUST910	Number of Customer Accounts	1,182,977	1,182,977	0	1,182,977	1,044,789	127,379	1,467	1,023	8,319
	Customer Service and Information	100.00%	100.00%	0.00%	100.00%	88.32%	10.77%	0.12%	0.09%	0.70%
22. CUST916	Number of Customer Accounts	1,184,446	1,182,977	1,469	1,182,977	1,044,789	127,379	1,467	1,023	8,319
	Sales Expense	100.00%	99.88%	0.12%	99.88%	88.21%	10.75%	0.12%	0.09%	0.70%
23. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	28,439,817	27,821,398	618,419	27,821,398	14,106,290	13,167,438	369,052	153,848	24,770
	System Benefits - Energy Related	100.00%	97.83%	2.17%	97.83%	49.60%	46.30%	1.30%	0.54%	0.09%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	General Service	(Church Rate) General Service	E-32 TOU (0-100kW)	E-32 TOU (101-400kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)	E-34	E-35
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	37.08%	0.30%	0.09%	0.18%	0.58%	0.51%	12.83%	9.14%	6.76%	2.24%	4.45%
	Production Demand	37.08%	0.30%	0.09%	0.18%	0.58%	0.51%	12.83%	9.14%	6.76%	2.24%	4.45%
2. DEMPROD6	Specific Assignment	0	0	0	0	0	0	0	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	0	0	0	0	0	0	0	0	0	0	0
	Transmission Substation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	0	0	0	0	0	0	0	0	0	0	0
	Transmission Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	2,722,500	23,845	6,886	12,097	45,384	38,392	1,016,993	650,410	509,739	137,822	280,932
	Distribution Substation	37.33%	0.33%	0.09%	0.17%	0.62%	0.53%	13.94%	8.92%	6.99%	1.89%	3.85%
6. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	2,653,510	23,241	6,711	11,791	44,234	37,419	991,221	633,928	496,822	134,330	273,813
	Distribution OH Primary Lines	37.33%	0.33%	0.09%	0.17%	0.62%	0.53%	13.94%	8.92%	6.99%	1.89%	3.85%
7. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	0	0	0	0	0	0	0	0	0	0	0
	Distribution OH Secondary Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	2,653,510	23,241	6,711	11,791	44,234	37,419	991,221	633,928	496,822	134,330	273,813
	Distribution UG Primary Lines	37.75%	0.33%	0.10%	0.17%	0.63%	0.53%	14.10%	9.02%	7.07%	1.91%	3.89%
9. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	0	0	0	0	0	0	0	0	0	0	0
	Distribution UG Secondary Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	2,021,771	28,136	9,434	13,041	45,764	40,172	1,393,698	491,526	0	0	0
	Distribution OH Line Transformers	21.93%	0.31%	0.10%	0.14%	0.50%	0.44%	15.11%	5.33%	0.00%	0.00%	0.00%
11. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	2,779,507	28,136	9,434	13,041	45,764	40,172	1,393,698	491,526	493,981	49,166	214,589
	Distribution UG Line Transformers	28.21%	0.29%	0.10%	0.13%	0.46%	0.41%	14.14%	4.99%	5.01%	0.50%	2.18%
12. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	36,113	118	97	42	0	67	35,108	680	0	0	0
	Distribution OH Services	11.98%	0.04%	0.03%	0.01%	0.00%	0.02%	11.65%	0.23%	0.00%	0.00%	0.00%
13. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	317,007	885	725	388	873	616	262,281	22,565	21,815	2,616	4,243
	Distribution UG Services	28.84%	0.08%	0.07%	0.04%	0.08%	0.06%	23.85%	2.05%	1.98%	0.24%	0.39%
14. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	2,653,510	23,241	6,711	11,791	44,234	37,419	991,221	633,928	496,822	134,330	273,813
	Distribution Rents	37.33%	0.33%	0.09%	0.17%	0.62%	0.53%	13.94%	8.92%	6.98%	1.89%	3.85%
15. ENERGY1	Customer Class Energy @ Generation (MWH)	13,167,438	41,349	40,726	75,181	281,190	117,838	4,263,784	3,352,488	2,622,747	801,426	1,570,709
	Production - Energy	46.28%	0.15%	0.14%	0.26%	0.99%	0.41%	14.98%	11.79%	9.22%	2.82%	5.52%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	General Service	(Church Rate) General Service	E-32 TOU (0-100kW)	E-32 TOU (101-400kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)	E-34	E-35
16. ENERGY2	Weighted Hourly Energy Allocator @ Generation	46.13%	0.15%	0.14%	0.26%	0.97%	0.41%	15.11%	11.78%	9.15%	2.78%	5.38%
	Production - Energy (Fuel and Purchased Power)	46.13%	0.15%	0.14%	0.26%	0.97%	0.41%	15.11%	11.78%	9.15%	2.78%	5.38%
17. CUST370	Weighted Costs for Distribution Meters ($)	237,926	2,600	1,172	404	780	755	193,237	25,147	10,581	1,529	1,720
	Distribution Meters	18.31%	0.20%	0.09%	0.03%	0.06%	0.06%	14.87%	1.94%	0.81%	0.12%	0.13%
18. CUST371	Dusk to Dawn Customer Class Specific	0	0	0	0	0	0	0	0	0	0	0
	Dusk to Dawn	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19. CUST373	Street Lighting Customer Class Specific	0	0	0	0	0	0	0	0	0	0	0
	Street Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20. CUSTNUM	Number of Customer Accounts	127,379	409	336	73	57	116	121,274	4,252	795	30	37
	Customer Accounts	10.76%	0.03%	0.03%	0.01%	0.00%	0.01%	10.25%	0.36%	0.07%	0.00%	0.00%
21. CUST910	Number of Customer Accounts	127,379	409	336	73	57	116	121,274	4,252	795	30	37
	Customer Service and Information	10.77%	0.03%	0.03%	0.01%	0.00%	0.01%	10.26%	0.36%	0.07%	0.00%	0.00%
22. CUST916	Number of Customer Accounts	127,379	409	336	73	57	116	121,274	4,252	795	30	37
	Sales Expense	10.75%	0.03%	0.03%	0.01%	0.00%	0.01%	10.24%	0.36%	0.07%	0.00%	0.00%
23. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	13,167,438	41,349	40,726	75,181	281,190	117,838	4,263,784	3,352,488	2,622,747	801,426	1,570,709
	System Benefits - Energy Related	46.30%	0.15%	0.14%	0.26%	0.99%	0.41%	14.99%	11.79%	9.22%	2.82%	5.52%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	Residential	Residential - Solar Demand Rates	Residential - Solar Energy Rates	E-12	ET-1 & ET-2	ECT-1 & ECT-2	
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	59.23%	0.11%	1.72%	15.65%	30.11%	11.64%	0.00
	Production Demand	59.23%	0.11%	1.72%	15.65%	30.11%	11.64%	0.00%
2. DEMPROD6	Specific Assignment	0	0	0	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	0	0	0	0	0	0	0
	Transmission Substation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	0	0	0	0	0	0	0
	Transmission Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	4,450,431	8,015	130,073	1,171,727	2,271,340	869,276	0
	Distribution Substation	61.04%	0.11%	1.78%	16.07%	31.16%	11.92%	0.00%
6. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	4,337,653	7,812	126,777	1,142,034	2,213,782	847,248	0
	Distribution OH Primary Lines	61.04%	0.11%	1.78%	16.07%	31.16%	11.92%	0.00%
7. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	6,908,554	11,693	198,649	2,137,411	3,344,350	1,216,451	0
	Distribution OH Secondary Lines	99.44%	0.17%	2.86%	30.77%	48.13%	17.51%	0.00%
8. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	4,337,653	7,812	126,777	1,142,034	2,213,782	847,248	0
	Distribution UG Primary Lines	61.66%	0.11%	1.80%	16.23%	31.48%	12.04%	0.00%
9. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	6,908,554	11,693	198,649	2,137,411	3,344,350	1,216,451	0
	Distribution UG Secondary Lines	99.44%	0.17%	2.86%	30.77%	48.13%	17.51%	0.00%
10. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	7,039,817	11,915	202,423	2,178,022	3,407,893	1,239,564	0
	Distribution OH Line Transformers	76.30%	0.13%	2.19%	23.61%	36.93%	13.44%	0.00%
11. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	7,039,817	11,915	202,423	2,178,022	3,407,893	1,239,564	0
	Distribution UG Line Transformers	71.39%	0.12%	2.05%	22.09%	34.56%	12.57%	0.00%
12. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	261,928	295	6,788	117,421	107,657	29,767	0
	Distribution OH Services	86.90%	0.10%	2.25%	38.96%	35.71%	9.88%	0.00%
13. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	782,860	881	20,290	350,951	321,770	88,969	0
	Distribution UG Services	71.16%	0.08%	1.84%	31.90%	29.25%	8.09%	0.00%
14. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	4,337,653	7,812	126,777	1,142,034	2,213,782	847,248	0
	Distribution Rents	61.04%	0.11%	1.78%	16.07%	31.16%	11.92%	0.00%
15. ENERGY1	Customer Class Energy @ Generation (MWH)	14,106,290	27,426	398,750	3,860,095	6,857,795	2,962,224	0
	Production - Energy	49.60%	0.10%	1.40%	13.57%	24.11%	10.42%	0.00%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	Residential	Residential - Solar Demand Rates	Residential - Solar Energy Rates	E-12	ET-1 & ET-2	ECT-1 & ECT-2	
16. ENERGY2	Weighted Hourly Energy Allocator @ Generation	49.85%	0.10%	1.41%	13.68%	24.25%	10.41%	0.00
	Production - Energy (Fuel and Purchased Power)	49.85%	0.10%	1.41%	13.68%	24.25%	10.41%	0.00%
17. CUST370	Weighted Costs for Distribution Meters ($)	1,044,789	1,176	27,078	468,372	429,427	118,736	0
	Distribution Meters	80.40%	0.09%	2.08%	36.04%	33.05%	9.14%	0.00%
18. CUST371	Dusk to Dawn Customer Class Specific	0	0	0	0	0	0	0
	Dusk to Dawn	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19. CUST373	Street Lighting Customer Class Specific	0	0	0	0	0	0	0
	Street Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20. CUSTNUM	Number of Customer Accounts	1,044,789	1,176	27,078	468,372	429,427	118,736	0
	Customer Accounts	88.21%	0.10%	2.29%	39.54%	36.26%	10.02%	0.00%
21. CUST910	Number of Customer Accounts	1,044,789	1,176	27,078	468,372	429,427	118,736	0
	Customer Service and Information	88.32%	0.10%	2.29%	39.59%	36.30%	10.04%	0.00%
22. CUST916	Number of Customer Accounts	1,044,789	1,176	27,078	468,372	429,427	118,736	0
	Sales Expense	88.21%	0.10%	2.29%	39.54%	36.26%	10.02%	0.00%
23. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	14,106,290	27,426	398,750	3,860,095	6,857,795	2,962,224	0
	System Benefits - Energy Related	49.60%	0.10%	1.40%	13.57%	24.11%	10.42%	0.00%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31,2014
($)

Line #	2014 Cost of Service	ELECTRIC TOTAL (1)	ACC JURISDICTION (2)	ALL OTHER (3)	TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	E-221 (Water Pumping) (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
1	**SUMMARY OF RESULTS**									
2										
3	**DEVELOPMENT OF RATE BASE**									
4	ELECTRIC PLANT IN SERVICE	$ 14,696,707,221	$ 12,461,310,312	$ 2,235,396,909	$ 12,461,310,312	$ 7,873,908,648	$ 4,310,123,653	$ 95,788,128	$ 129,497,556	$ 51,992,326
5	GENERAL & INTANGIBLE PLANT	1,399,767,310	1,293,230,475	106,536,835	1,293,230,475	852,085,017	417,906,299	11,173,933	8,027,437	4,037,789
6	LESS: RESERVE FOR DEPRECIATION	(6,173,357,275)	(5,390,237,335)	(783,119,940)	(5,390,237,335)	(3,400,040,425)	(1,880,485,209)	(45,796,324)	(46,224,142)	(17,691,235)
7	OTHER DEFERRED CREDITS	(1,225,088,587)	(1,169,199,077)	(55,889,510)	(1,169,199,077)	(707,151,484)	(441,199,733)	(12,223,376)	(6,625,086)	(1,999,398)
8	WORKING CASH	(101,350,672)	(84,517,428)	(16,833,244)	(84,517,428)	(54,258,104)	(28,376,526)	(614,571)	(906,554)	(361,674)
9	MATERIALS, SUPPLIES & PREPAYMENTS	409,194,079	367,468,477	41,725,602	367,468,477	213,464,249	146,393,612	3,737,240	2,908,959	964,417
10	ACCUM. DEFERRED TAXES	(2,639,765,552)	(2,206,834,700)	(432,930,852)	(2,206,834,700)	(1,413,363,736)	(743,357,519)	(15,874,443)	(24,246,078)	(9,992,924)
11	REGULATORY ASSETS	373,194,607	324,563,826	48,630,781	324,563,826	230,084,643	88,270,395	2,112,479	2,531,984	1,564,325
12	DECOMMISSIONING FUND	713,866,000	699,088,974	14,777,026	699,088,974	422,822,832	264,701,513	7,566,980	3,426,557	571,093
13	GAIN FROM DISP. OF PLANT	(4,887,000)	(4,785,839)	(101,161)	(4,785,839)	(2,894,570)	(1,812,100)	(51,802)	(23,458)	(3,910)
14	MISCELLANEOUS DEFERRED DEBITS	125,606,562	102,010,534	23,596,028	102,010,534	66,010,041	34,154,949	918,340	627,237	299,966
15	CUSTOMER ADVANCES	(123,052,363)	(103,193,820)	(19,858,543)	(103,193,820)	(63,518,034)	(39,346,022)	(153,279)	(175,744)	(741)
16	CUSTOMER DEPOSITS	(72,306,606)	(72,306,606)		(72,306,606)	(37,599,435)	(33,257,771)	(739,563)	(498,448)	(211,388)
17	**TOTAL RATE BASE**	**7,378,527,724**	**6,216,597,792**	**1,161,929,932**	**6,216,597,792**	**3,979,549,643**	**2,093,715,540**	**45,843,743**	**68,320,220**	**29,168,646**
18										
19	**DEVELOPMENT OF RETURN**									
20	REVENUES FROM RATES	2,896,933,742	2,828,139,997	68,793,745	2,828,139,997	1,437,421,622	1,332,634,743	29,640,752	19,973,390	8,469,490
21	OTHER ELECTRIC REVENUE	592,011,071	565,177,360	26,833,710	565,177,360	311,955,249	242,388,439	7,668,313	2,474,819	690,541
22	**TOTAL OPERATING REVENUES**	**3,488,944,813**	**3,393,317,357**	**95,627,455**	**3,393,317,357**	**1,749,376,871**	**1,575,023,182**	**37,309,065**	**22,448,209**	**9,160,031**
23										
24	**OPERATING EXPENSES**									
25	OPERATION & MAINTENANCE	1,876,691,588	2,012,076,433	(135,384,845)	2,012,076,433	1,061,535,946	911,914,839	25,764,871	10,304,703	2,556,074
26	ADMINISTRATIVE & GENERAL	218,678,783	200,092,070	18,586,713	200,092,070	132,501,024	63,974,302	1,697,758	1,270,138	648,849
27	DEPRECIATION & AMORT EXPENSE	437,911,200	384,549,577	53,361,623	384,549,577	243,678,093	132,717,114	3,113,558	3,573,852	1,466,959
28	AMORTIZATION ON GAIN	(4,233,612)	(4,146,332)	(87,280)	(4,146,332)	(2,540,326)	(1,538,461)	(44,068)	(20,114)	(3,363)
29	REGULATORY ASSETS	(31,155,535)	(31,155,535)		(31,155,535)	(18,843,483)	(11,796,663)	(337,229)	(152,708)	(25,451)
30	TAXES OTHER THAN INCOME	171,583,429	141,004,082	30,579,347	141,004,082	90,279,756	47,407,007	972,785	1,645,307	699,227
31	INCOME TAX	249,269,119	210,201,180	39,067,939	210,201,180	56,371,627	149,039,287	1,960,206	1,618,045	1,212,013
32	**TOTAL OPERATING EXPENSES**	**2,918,744,972**	**2,912,621,475**	**6,123,497**	**2,912,621,475**	**1,562,982,637**	**1,291,717,426**	**33,127,881**	**18,239,224**	**6,554,308**
33										
34	**OPERATING INCOME**	**$ 570,199,841**	**$ 480,695,882**	**$ 89,503,959**	**$ 480,695,882**	**$ 186,394,234**	**$ 283,305,756**	**$ 4,181,184**	**$ 4,208,985**	**$ 2,605,723**
35										
36	**RETURN**	**570,199,841**	**480,695,882**	**89,503,959**	**480,695,882**	**186,394,234**	**283,305,756**	**4,181,184**	**4,208,985**	**2,605,723**
37										
38	**RATE OF RETURN (PRESENT)**	**7.73%**	**7.73%**	**7.70%**	**7.73%**	**4.68%**	**13.53%**	**9.12%**	**6.16%**	**8.93%**
39										
40	**INDEX RATE OF RETURN (PRESENT)**	**1.00**	**1.00**	**1.00**	**1.00**	**0.61**	**1.75**	**1.18**	**0.80**	**1.16**
41										
42	**REVENUE REQUIREMENT @ 8.07%**	**2,938,457,585**	**2,862,651,331**	**75,806,254**	**2,862,651,331**	**1,659,025,311**	**1,144,603,209**	**28,848,821**	**22,118,576**	**8,055,413**
43										
44	**% OF TOTAL COST OF SERVICE (Line 20/Line42)**	**98.59%**	**98.79%**	**90.75%**	**98.79%**	**86.64%**	**116.43%**	**102.75%**	**90.30%**	**105.14%**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31,2014
($)

Line #	2014 Cost of Service	TOTAL GENERAL SERVICE (10)	E-20 (Church Rate) (11)	E-32 TOU (0-100kW) (12)	E-32 TOU (101-400kW) (13)	E-32 TOU (401+ kW) (14)	School TOU (15)	E-30, E-32 (0 - 100 kW) (16)	E-32 (101 - 400 kW) (17)	E-32 (401+ kW) (18)	E-34 (19)	E-35 (20)
1	SUMMARY OF RESULTS											
2												
3	DEVELOPMENT OF RATE BASE											
4	ELECTRIC PLANT IN SERVICE	$ 4,310,123,653	$ 35,465,034	$ 11,035,090	$ 20,038,100	$ 67,819,345	$ 57,962,198	$1,632,916,352	$1,017,355,664	$ 767,997,651	$ 230,796,405	$ 468,737,814
5	GENERAL & INTANGIBLE PLANT	417,906,299	2,936,164	1,144,355	1,916,946	6,459,431	4,804,818	168,910,053	95,131,173	70,645,864	22,106,648	43,850,848
6	LESS: RESERVE FOR DEPRECIATION	(1,880,485,209)	(15,243,058)	(4,781,134)	(8,797,111)	(29,315,512)	(25,066,230)	(704,629,757)	(446,230,399)	(334,126,582)	(103,625,655)	(208,669,771)
7	OTHER DEFERRED CREDITS	(441,199,733)	(2,924,543)	(1,180,540)	(2,195,358)	(7,478,100)	(5,286,334)	(157,947,882)	(107,137,744)	(80,521,359)	(25,673,854)	(50,854,020)
8	WORKING CASH	(28,376,526)	(261,715)	(69,000)	(127,496)	(418,359)	(410,406)	(10,840,254)	(6,664,970)	(4,988,377)	(1,510,464)	(3,085,485)
9	MATERIALS, SUPPLIES & PREPAYMENTS	146,393,612	828,991	413,746	757,489	2,705,215	1,632,284	51,519,122	35,882,297	27,549,623	8,396,144	16,708,701
10	ACCUM. DEFERRED TAXES	(743,357,519)	(6,479,695)	(1,869,274)	(3,378,740)	(11,323,857)	(10,315,205)	(286,044,669)	(173,989,362)	(131,024,802)	(39,104,849)	(79,827,065)
11	REGULATORY ASSETS	88,270,395	718,282	242,579	355,508	1,168,922	1,023,396	40,805,765	18,405,997	13,447,478	4,023,705	8,078,763
12	DECOMMISSIONING FUND	264,701,513	2,141,598	642,479	1,284,959	4,140,423	3,640,717	91,589,008	65,247,352	48,257,342	15,990,598	31,767,037
13	GAIN FROM DISP. OF PLANT	(1,812,100)	(14,661)	(4,398)	(8,797)	(28,345)	(24,924)	(627,002)	(446,672)	(330,361)	(109,469)	(217,472)
14	MISCELLANEOUS DEFERRED DEBITS	34,154,949	226,004	94,755	160,828	549,508	383,869	13,498,701	7,877,516	5,886,741	1,837,463	3,639,566
15	CUSTOMER ADVANCES	(39,346,022)	(125,459)	(123,621)	(193,785)	(650,007)	(329,953)	(14,814,576)	(10,105,587)	(7,207,275)	(1,833,122)	(3,962,637)
16	CUSTOMER DEPOSITS	(33,257,771)	(104,611)	(104,702)	(163,820)	(549,685)	(277,326)	(12,531,157)	(8,544,916)	(6,092,303)	(1,545,426)	(3,343,825)
17	TOTAL RATE BASE	2,093,715,540	17,162,329	5,440,336	9,648,724	33,078,978	27,736,904	811,803,703	486,780,348	369,493,640	109,748,124	222,822,454
18												
19	DEVELOPMENT OF RETURN											
20	REVENUES FROM RATES	1,332,634,743	4,192,158	4,194,856	6,564,382	22,028,749	11,114,344	502,045,850	342,410,751	244,146,500	61,931,557	134,005,594
21	OTHER ELECTRIC REVENUE	242,388,439	1,069,414	809,770	1,189,439	3,705,644	2,360,388	99,550,621	61,544,569	39,015,468	11,288,437	21,854,687
22	TOTAL OPERATING REVENUES	1,575,023,182	5,261,573	5,004,627	7,753,821	25,734,393	13,474,732	601,596,471	403,955,320	283,161,968	73,219,995	155,860,281
23												
24	OPERATING EXPENSES											
25	OPERATION & MAINTENANCE	911,914,839	3,698,238	2,605,547	4,504,544	16,247,189	8,473,906	309,443,816	219,299,899	179,515,623	53,540,511	114,585,565
26	ADMINISTRATIVE & GENERAL	63,974,302	455,510	174,937	291,243	979,511	738,313	26,057,883	14,496,761	10,755,428	3,357,936	6,666,779
27	DEPRECIATION & AMORT EXPENSE	132,717,114	1,032,881	347,037	621,459	2,109,619	1,709,706	50,597,078	31,221,507	23,519,520	7,144,151	14,414,157
28	AMORTIZATION ON GAIN	(1,538,461)	(13,227)	(3,629)	(7,334)	(23,165)	(21,917)	(535,817)	(377,944)	(277,817)	(92,867)	(184,746)
29	REGULATORY ASSETS	(11,796,663)	(95,442)	(28,633)	(57,265)	(184,522)	(162,252)	(4,081,747)	(2,907,808)	(2,150,632)	(712,636)	(1,415,727)
30	TAXES OTHER THAN INCOME	47,407,007	398,742	122,153	216,576	739,177	640,296	18,412,432	11,044,555	8,370,821	2,449,924	5,012,332
31	INCOME TAX	149,039,287	(251,503)	647,410	762,148	1,976,862	551,479	71,138,839	46,666,637	21,258,270	1,883,020	4,406,124
32	TOTAL OPERATING EXPENSES	1,291,717,426	5,225,200	3,864,822	6,331,370	21,844,672	11,929,532	471,032,485	319,443,608	240,991,214	67,570,038	143,484,485
33												
34	OPERATING INCOME	$ 283,305,756	$ 36,373	$ 1,139,804	$ 1,422,451	$ 3,889,721	$ 1,545,201	$ 130,563,986	$ 84,511,712	$ 42,170,755	$ 5,649,956	$ 12,375,796
35												
36	RETURN	283,305,756	36,373	1,139,804	1,422,451	3,889,721	1,545,201	130,563,986	84,511,712	42,170,755	5,649,956	12,375,796
37												
38	RATE OF RETURN (PRESENT)	13.53%	0.21%	20.95%	14.74%	11.76%	5.57%	16.08%	17.36%	11.41%	5.15%	5.55%
39												
40	INDEX RATE OF RETURN (PRESENT)	1.75	0.03	2.71	1.91	1.52	0.72	2.08	2.25	1.48	0.67	0.72
41												
42	REVENUE REQUIREMENT @ 8.07%	1,144,603,209	6,409,942	3,042,469	5,505,683	20,022,118	12,254,255	395,071,562	268,034,299	223,833,308	67,204,977	143,224,596
43												
44	% OF TOTAL COST OF SERVICE (Line 20/Line42)	116.43%	65.40%	137.88%	119.23%	110.02%	90.70%	127.08%	127.75%	109.08%	92.15%	93.56%

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31,2014
($)

Line #	2014 Cost of Service	TOTAL RESIDENTIAL (21)	RESIDENTIAL SOLAR (ENERGY) (22)	RESIDENTIAL SOLAR (DEMAND) (23)	RESIDENTIAL E-12 (24)	RESIDENTIAL ET-1 & ET-2 (25)	RESIDENTIAL ECT-1 & ECT-2 (26)
1	**SUMMARY OF RESULTS**						
2							
3	**DEVELOPMENT OF RATE BASE**						
4	ELECTRIC PLANT IN SERVICE	$ 7,873,908,648	$ 227,066,300	$ 13,974,152	$ 2,220,780,957	$ 3,929,347,969	$1,482,739,270
5	GENERAL & INTANGIBLE PLANT	852,085,017	23,801,280	1,377,171	278,800,684	403,251,817	144,854,065
6	LESS: RESERVE FOR DEPRECIATION	(3,400,040,425)	(97,754,814)	(6,010,997)	(968,817,303)	(1,690,971,271)	(636,486,039)
7	OTHER DEFERRED CREDITS	(707,151,484)	(20,168,625)	(1,260,897)	(204,037,048)	(348,020,690)	(133,664,223)
8	WORKING CASH	(54,258,104)	(1,573,588)	(96,681)	(15,011,121)	(27,334,068)	(10,242,645)
9	MATERIALS, SUPPLIES & PREPAYMENTS	213,464,249	6,099,954	390,204	60,090,414	105,222,632	41,661,045
10	ACCUM. DEFERRED TAXES	(1,413,363,736)	(40,813,063)	(2,496,130)	(398,947,345)	(706,454,669)	(264,652,528)
11	REGULATORY ASSETS	230,084,643	6,359,919	346,704	80,577,581	106,555,014	36,245,426
12	DECOMMISSIONING FUND	422,822,832	12,278,495	785,253	111,720,029	214,945,053	83,094,002
13	GAIN FROM DISP. OF PLANT	(2,894,570)	(84,056)	(5,376)	(764,816)	(1,471,476)	(568,847)
14	MISCELLANEOUS DEFERRED DEBITS	66,010,041	1,845,547	108,054	21,367,143	31,301,992	11,387,304
15	CUSTOMER ADVANCES	(63,518,034)	(636,180)	(84,322)	(19,174,546)	(31,437,442)	(12,185,543)
16	CUSTOMER DEPOSITS	(37,599,435)	(370,358)	(49,741)	(11,362,681)	(18,604,967)	(7,211,688)
17	**TOTAL RATE BASE**	**3,979,549,643**	**116,050,811**	**6,977,393**	**1,155,221,949**	**1,966,329,893**	**734,969,598**
18							
19	**DEVELOPMENT OF RETURN**						
20	REVENUES FROM RATES	1,437,421,622	14,156,717	1,901,647	434,362,994	711,276,594	275,723,670
21	OTHER ELECTRIC REVENUE	311,955,249	5,574,020	446,431	93,540,065	151,316,821	61,077,912
22	**TOTAL OPERATING REVENUES**	**1,749,376,871**	**19,730,738**	**2,348,078**	**527,903,058**	**862,593,415**	**336,801,582**
23							
24	**OPERATING EXPENSES**						
25	OPERATION & MAINTENANCE	1,061,535,946	19,172,212	1,503,007	303,128,486	522,984,567	214,747,674
26	ADMINISTRATIVE & GENERAL	132,501,024	3,699,772	213,306	43,509,755	62,650,449	22,427,742
27	DEPRECIATION & AMORT EXPENSE	243,678,093	6,975,271	425,091	71,080,821	120,157,603	45,039,307
28	AMORTIZATION ON GAIN	(2,540,326)	(73,900)	(4,703)	(669,626)	(1,295,140)	(496,957)
29	REGULATORY ASSETS	(18,843,483)	(547,202)	(34,995)	(4,978,905)	(9,579,221)	(3,703,160)
30	TAXES OTHER THAN INCOME	90,279,756	2,600,644	158,466	25,800,529	44,901,732	16,818,386
31	INCOME TAX	56,371,627	(5,870,999)	(33,522)	24,029,501	28,959,146	9,287,501
32	**TOTAL OPERATING EXPENSES**	**1,562,982,637**	**25,955,798**	**2,226,649**	**461,900,561**	**768,779,136**	**304,120,493**
33							
34	**OPERATING INCOME**	**$ 186,394,234**	**$ (6,225,060)**	**$ 121,429**	**$ 66,002,497**	**$ 93,814,279**	**$ 32,681,089**
35							
36	**RETURN**	**186,394,234**	**(6,225,060)**	**121,429**	**66,002,497**	**93,814,279**	**32,681,089**
37							
38	**RATE OF RETURN (PRESENT)**	**4.68%**	**(5.36%)**	**1.74%**	**5.71%**	**4.77%**	**4.45%**
39							
40	**INDEX RATE OF RETURN (PRESENT)**	**0.61**	**(0.69)**	**0.23**	**0.74**	**0.62**	**0.58**
41							
42	**REVENUE REQUIREMENT @ 8.07%**	**1,659,025,311**	**39,794,627**	**2,627,925**	**479,132,655**	**817,952,180**	**319,517,925**
43							
44	**% OF TOTAL COST OF SERVICE (Line 20/Line42)**	**86.64%**	**35.57%**	**72.36%**	**90.66%**	**86.96%**	**86.29%**

REBUTTAL TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

EXHIBIT
APS-2
ADMITTED

April 7, 2016

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REBUTTAL TESTIMONY OF LELAND R. SNOOK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Leland R. Snook. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Director of Rates and Rate Strategy for Arizona Public Service Company (APS or Company). I have management responsibility for all aspects relating to rate strategy and specific rates and prices.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed direct testimony on February 25, 2016.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony, I address the direct testimony of those witnesses who have incorrectly applied either the principles of ratemaking based on a Cost Of Service Study (COSS) or introduced a flawed analysis regarding rate design.

- First, I address the testimony of Vote Solar witness Ms. Briana Kobor, who incorrectly claims that:
    - A COSS is a short-term evaluation of costs;
    - Rooftop solar customers are no different than customers that participate in energy efficiency or electric vehicles;
    - It is difficult to assess the value of Distributed Generation in a COSS;

- A utility's ratepayers pay the large upfront capital costs when a utility builds a power plant; and
- An energy-only time-of-use (TOU) rate would encourage orientation of rooftop solar systems that provide more capacity benefit.

Additionally, I will address Ms. Kobor's apparent misunderstanding of the relationship and distinctions between setting rates and resource planning.

- Second, I will address the direct testimony of The Alliance for Solar Choice (TASC) witness Mr. R. Thomas Beach, who erroneously suggests that:
  - A traditional energy efficiency analysis should be used in a Value of Solar (VOS) analysis for setting rates;
  - A COSS is a short-term analysis;
  - Energy only TOU rates are all that is needed to address rooftop solar rate design issues, or alternatively, a minimum bill approach would be appropriate;
  - A rooftop solar customer is no different than a customer engaging in energy efficiency;
  - Resource planning and ratemaking can be combined into one process;
  - The current state of rate design and rooftop solar has created competitive choice; and
  - Demand charges would overcharge rooftop solar customers and be inappropriate as a rate design approach for customers.

Also, I correct the record where Mr. Beach has misstated the findings of the Energy+Environmental Economics (E3) study in Nevada, as well as the Public Utilities Commission of Nevada.

- Third, I address the testimony of the Residential Utility Consumer Office (RUCO) witness Mr. Lon Huber. I put into its proper context Mr. Huber's reference to Professor Bonbright's discussion of value-based rates. I also clarify Mr. Huber's reference to value in Decision No. 73130, which authorized APS to proceed with the acquisition of Southern California Edison's (SCE) share of Four Corners Units 4 and 5, but did not make any determination regarding the future rate treatment of such an acquisition.

II. <u>RESPONSE TO THE TESTIMONY OF VOTE SOLAR WITNESS MS. BRIANA KOBOR</u>

Q. MS. KOBOR SUGGESTS THAT A COSS IS A SHORT-TERM EVALUATION OF COSTS. DO YOU AGREE WITH MS. KOBOR ON THIS POINT?

A. No. Ms. Kobor apparently misunderstands the nature of a COSS by mischaracterizing it as a "short term" look at costs. A COSS is based on a full 12-month test-year period, and provides a comprehensive historical look at the entirety of a utility's actual costs for every item of utility plant and property that is dedicated to providing service to its customers, many with asset lives of 40 years or more, as well as the full extent of all expenses presently incurred in the provision of service.

In a cost of service regulated environment, the COSS is the foundational tool for determining the authorized level of revenue and for setting just and reasonable rates. To refer to a COSS as a short-term evaluation of costs grossly over-simplifies the comprehensive nature of the tool, the conclusions that can be drawn from the actual and quantifiable data in the study and the importance a COSS has in the rate setting process.

Ms. Kobor does not indicate what benefit, if any, would be served by a "long term" look at actual costs. The historical and factual analysis provided by a COSS has proven to be and is a reliable and verifiable basis for setting future rates, and is vastly superior to relying on subjective and speculative expectations of "value" projected decades into the future.

Moreover, the COSS demonstrates and incorporates the actual benefits provided by rooftop solar. The COSS can be considered a holistic analysis that fully looks at all quantifiable costs and benefits.

Q. MS. KOBOR ALSO INDICATES THAT A ROOFTOP SOLAR CUSTOMER IS NO DIFFERENT THAN CUSTOMERS WHO PARTICIPATE IN OTHER ACTIVITIES, SUCH AS ENERGY EFFICENCY, AND ELECTRIC VEHICLES. MS. KOBOR INDICATES THE ONLY DIFFERENCE IS THAT THE ROOFTOP SOLAR CUSTOMER SOMETIMES EXPORTS ENERGY TO THE GRID. DO YOU AGREE WITH THIS ASSESSMENT?

A. No. Ms. Kobor's statement is factually and empirically incorrect. The load shape data I provided at pages 26 and 27 of my direct testimony squarely controverts Ms. Kobor's assertion.

As clearly supported by the data, the load shapes of rooftop solar customers are dramatically different than the load shape of residential customers without rooftop solar, even if a residential customer lives in an apartment, has natural gas appliances in her home, engages in energy efficiency or only lives in Arizona during the milder winter time of year.

In contrast to this uncontroverted data, Ms. Kobor has only offered her unsubstantiated assertion that the load shapes are similar, without any factual evidence. Again, the uncontroverted data I have presented in my direct testimony disproves the notion that there is no difference in these types of customers. The reality is that rooftop solar customers have monthly energy consumption equivalent to a small apartment and they continue to have a maximum demand on the system that is much closer to what their demand was prior to installing rooftop solar.

Q. MS. KOBOR ASSERTS THAT IT IS DIFFICULT TO ASSESS THE VALUE OF ROOFTOP SOLAR IN A COSS AND THAT A COSS IS ILL-SUITED TO PERFORM THE EVALUATION. DO YOU AGREE?

A. Again, Ms. Kobor is incorrect on several levels.

First, a COSS is a ratemaking tool that has been used in ratemaking proceedings for many decades to produce what public utility commissions and courts throughout the country have confirmed are just and reasonable rates. Ms. Kobor's apparent goal in this proceeding is to persuade us that a VOS analysis, which plays a role in a resource planning context (not ratemaking), should immediately be force-fed into the ratesetting process.

As I indicated previously, a COSS is the foundational tool in determining the appropriate level of revenues based on the facilities a utility has dedicated to serving customers, and is a comprehensive look at actual costs <u>incurred</u> in the provision of utility service.

Further, the COSS is the factual basis for establishing just and reasonable rates. As I indicated in my direct testimony in this docket, there should be no confusion between a COSS that is used to establish rates based on historical costs and a resource planning exercise that is used to evaluate various resource options based on projections of future events. They are not the same, do not serve the same purpose, and never were intended to do so. As I indicated in my direct testimony in this proceeding, a VOS analysis is an appropriate tool for calibrating the price paid for energy exported to the grid from rooftop solar.

Q. WHY SHOULD RATES ONLY BE SET ON ACTUAL COSTS RATHER THAN THROUGH A RESOURCE PLANNING ANALYSIS?

A. The resource planning process compares resources on a level playing field of assumptions to determine which resources perform better under a variety of scenarios. It is a comparative tool that is updated formally every two years (and updated as needed during a procurement process or decision timeline) to keep pace with the ever-changing assumptions. Resources are procured using the best available information concerning future events. Once a resource decision is made, the utility procures the resource and incurs the cost. It is only then that the ratemaking process takes over.

Actual costs are used for the ratemaking process in a COSS, not the type of assumptions that are used during the resource planning process. To base rates on anything but actual costs would create significant risks based upon the accuracy of the assumptions used, which accuracy no one can guaranty. As opposed to just and reasonable rates, customers could be unfairly subject to rates that were too high and have no basis in fact. Alternatively, if the rates were too low, a utility would be at risk for not having sufficient resources to maintain the grid or pay back investors. Neither scenario could be said to involve just or reasonable rates.

Q. MS. KOBOR INDICATES THAT A UTILITY'S RATEPAYERS PAY THE LARGE UPFRONT CAPITAL COSTS WHEN A UTILITY BUILDS A POWER PLANT. IS THIS STATEMENT CORRECT?

A. No. I was quite surprised when I read Ms. Kobor's testimony on this point. It suggests a disconnect regarding how utility plant dedicated to providing service to customers is financed and eventually recovered in retail rates.

A utility finances all of its assets using a combination of debt and equity. Customers pay for these assets over their useful life in rates. Customers' payments can be likened to a mortgage payment. Mortgage payments include principal, which is similar to depreciation for utilities, and interest, which is the utility's cost of financing. Just as a bank might pay for a home upfront, with the homeowner paying the bank back over time through a mortgage, customers never pay the upfront cost for utility assets, the utility does.

Q. MS. KOBOR ALSO CLAIMS THAT AN ENERGY-ONLY TOU RATE WOULD ENCOURAGE ORIENTATION OF ROOFTOP SOLAR SYSTEMS THAT PROVIDE A GREATER CAPACITY BENEFIT. DO YOU AGREE?

A. No. I do not agree. Once again, Ms. Kobor makes a sweeping claim but offers no facts to support this assertion. And in reality, this claim is yet another that is directly contrary to the facts.

APS has the largest adoption of TOU rates in the United States. More than 53% of APS's residential customers are served under a TOU rate. APS's demand-based rates for residential customers are also TOU rates. Approximately 60% of APS's rooftop solar customers take service under an energy only TOU rate, and the evidence suggests this has had no effect on system orientation to provide a greater capacity benefit. Rather, the evidence shows that these customers still install their rooftop systems to maximize energy production under an energy-only TOU rate.

III. RESPONSE TO THE TESTIMONY OF TASC WITNESS MR. R. THOMAS BEACH

Q. MR. BEACH SUGGESTS THAT A VALUE OF SOLAR ANALYSIS SHOULD USE TRADITIONAL ENERGY EFFICIENCY ANALYSIS METHODS TO DETERMINE THE VALUE OF ROOFTOP SOLAR. DO YOU AGREE?

A. No, I do not. While there are some methods that have become somewhat standardized for energy efficiency analysis, they are used to compare different energy efficiency programs and to evaluate how various programs compare to each other. Like any resource planning tool, these methods are solely designed to facilitate selecting which programs should be offered. The analysis in energy efficiency programs is not used to determine any rate treatment or setting of rates.

Q. MR. BEACH CONTENDS THAT AN ENERGY-ONLY TOU RATE OR A MINIMUM BILL WOULD ADEQUATELY ADDRESS ROOFTOP SOLAR RATE DESIGN FLAWS. DO YOU AGREE?

A. No. Mr. Beach misunderstands the relationship between cost drivers and the rate features that would correlate to the cost drivers.

Approximately 70% of APS's costs are driven by either fixed costs that do not vary or costs that only vary with a customer's demand. Only 30% of APS's costs vary with a customer's consumption of energy. Using an energy price, even a TOU price, does not and cannot accurately reflect the cost of providing service because it relies on a bill element that does not match what actually drives the cost to be recovered.

APS's experience with energy TOU rates proves the point. APS perhaps has the most robust residential TOU rate in the country. Yet, APS is also experiencing some of the most extreme rooftop solar-related cost shifts.

Regarding minimum bills, I don't believe they can be designed in a way that is reasonable, fair, and effective. A one-size-fits-all approach to a minimum bill that is sized appropriately would function as a very high customer charge, and would be very regressive, among other flaws. The alternative is to set a one-size-fits-all minimum bill that is reasonable for a small residential customer. But this would be tantamount to maintaining the status quo, as the vast majority of all customers, including rooftop solar customers, already pay monthly bills in excess of that amount. Further, the minimum bill lacks the precision of a demand rate. A demand rate would bill each customer uniquely for their actual demand, creating a price signal that provides the customer with more control.

Q. DOES MR. BEACH CONFUSE RESOURCE PLANNING EXERCISES WITH THE RATEMAKING PROCESS?

A. Yes, he does. Similar to Ms. Kobor's misunderstanding, Mr. Beach suggests that the VOS analysis is directly applicable to the rate setting process in assessing the economics of rooftop solar. As I have pointed out previously, COSS is the foundational tool for establishing rates, while a VOS is a resource planning analysis. The two are not the same and should not be confused as serving the same purpose. Moreover, it is not clear how rates set by a resource planning tool could be found to be just or reasonable in Arizona.

Q. DO YOU BELIEVE, AS MR. BEACH SUGGESTS, THAT UNDER THE CURRENT STATE OF RATE DESIGN, ROOFTOP SOLAR PROVIDERS HAVE SOMEHOW CREATED COMPETITIVE CHOICE FOR CUSTOMERS?

A. No. Essentially, the current rate design allows rooftop solar customers to exploit a flaw in APS's tariffs; it doesn't provide an actual competitive alternative. Instead of cost-based competition, rooftop solar is heavily subsidized through today's flawed rate design and significant tax incentives. Moreover, without services provided by the grid, rooftop solar could not function. It is simply not an "all-in" alternative to traditional electric service, and customers who install rooftop solar still depend on the grid 24 hours a day.

Q. MR. BEACH CLAIMS THE STUDY SUBMITTED IN NEVADA, WHICH WAS CONDUCTED BY E3, FOUND THAT THE VALUE OF ROOFTOP SOLAR EXCEEDED ITS COSTS. IS MR. BEACH CORRECT?

A. No, Mr. Beach is not correct. One significant factor that Mr. Beach does not mention is that the renewable portfolio standard in Nevada had an initial extra-credit multiplier of 2.45 (2.45x) for rooftop solar through 2015. E3 used this 2.45x in assessing the value of rooftop solar, which artificially increased that value in relation to other renewable resources. If you erase this multiplier, in all E3 cases except the participant cost test, the economics in the original study flip.[1] Further, E3 found rooftop solar to be a net benefit if grid-scale solar's price was $100/MWh. But this net benefit (of $36 million) became a net cost of over $220 million if grid-scale solar was priced at $80/MWh. And, in September 2015 the Public Utilities Commission of Nevada found the price of grid-scale solar to be below $50/MWh. This is why the Public Utilities Commission of Nevada (PUCN) in their recent decision on net metering concluded that the E3 study had become irrelevant.[2]

Q. DO YOU AGREE WITH MR. BEACH THAT DEMAND CHARGES WOULD OVERCHARGE ROOFTOP SOLAR CUSTOMERS?

A. No. Rooftop solar does not permit utilities to avoid costs. Demand charges that are aligned with the cost to provide service would send the proper price information to all customers, including rooftop solar customers. Mr. Beach, by contrast, bases his assertion on hypothetical future values that cannot be netted against costs incurred in a historical test year that form the basis of rates.

IV. RESPONSE TO THE TESTIMONY OF RUCO WITNESS MR. LON HUBER

Q. RUCO WITNESS MR. HUBER REFERS TO PROFESSOR BONBRIGHT IN CONNECTION WITH VALUE-BASED RATES. DO YOU HAVE ANY THOUGHTS ON MR. HUBER'S PERSPECTIVE?

A. Yes, I do. Mr. Huber references some language in Professor Bonbright's book, "Principles of Public Utility Rates" that references value-based rates with cost of service ratemaking. However, Professor Bonbright did not conclude that value should be the basis for setting rates. Professor Bonbright only discussed value-based rates as one option in a potential spectrum of possible ways to set rates. Consistent with Professor

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[1] In fact, the E3 study acknowledges this: "When the RPS multiplier is removed…we find that NEM will again be a net cost to the state." ENERGY+ENVIRONMENTAL ECONOMICS, NEVADA NET ENERGY METERING IMPACTS EVALUATION page 11 (2014).

[2] *In re* Nev. Power Co. d/b/a NV Energy for Approval of a Cost-of-Service Study and Net Metering Tariffs, Modified Final Order in Docket Nos. 15-07041, 15-07042 page 48 n.19 (Nev. Pub. Utils. Comm'n Feb. 17, 2016).

Bonbright's conclusion, value based rates are not used. Rates for utilities, either at retail or wholesale, have only been set based on the cost of service or at a market price.

I do not believe that Professor Bonbright even tacitly endorsed using value to set retail utility rates. In fact, Bonbright concedes the hypothetical nature of his discussion by stating the following at the beginning of the chapter referred to by Mr. Huber, "Postponing for later discussion the formidable problem of defining value of service so as to qualify it as a definite standard for ratemaking...".[3] I do not believe that one can properly cite Professor Bonbright as a source in support of setting rates based on a value of solar analysis.

Q. MR. HUBER ALSO SUGGESTS THAT APS'S RECENT DECISION ON THE ACQUISITION OF SCE'S SHARE OF FOUR CORNERS UNITS 4 AND 5 HAD A RECOGNITION OF VALUE. PLEASE CLARIFY HOW THE FOUR CORNERS DECISION DISCUSSED THE CONCEPT OF VALUE.

A. Decision No. 73130 authorized APS to proceed with the acquisition of SCE's interest in Four Corners Units 4 and 5, but did not make any determination regarding the future rate treatment of such an acquisition. The discussion of value in that Decision addressed the self-build moratorium that was in effect for APS at the time and one of the conditions under which APS would be allowed a waiver under the moratorium. Most significantly, the proceeding was a resource planning decision to authorize an acquisition, not a rate setting decision. In fact, Decision No. 73130 demonstrates how value can be used in connection with resource planning decisions before and independent of the setting of rates based on the costs associated with that resource planning decision.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[3] JAMES C. BONBRIGHT ET AL., PRINCIPLES OF PUBLIC UTILITY RATES 125 (Pub. Utils. Reports, Inc., 2nd ed. 1998).

KEY TERMS:

Coincident Peak ("CP") - refers to the relative contribution of each customer class or sub-group at the time of system peak. If several months are used, such as the four summer months of June through September, this would be referred to as 4 CP.

Non-Coincident Peak ("NCP") - refers to the peak of each customer class or sub-group, independent from the time of system peak. This may also be referred to as the class peak or sub-group peak.

Delivered Load - refers to the energy delivered to a customer by the utility. For full-requirements customers, this is equal to all of their energy consumption. For a rooftop solar partial requirements customer, this is just the portion of energy needs supplied by the utility on a moment by moment basis.

Site Load - for a rooftop solar partial requirements customer, this refers to the sum of the utility Delivered Load and the energy that is self-provided by the rooftop solar array. For a full-requirements customer, this is equal to the Delivered Load.

EXHIBIT
APS-3
ADMITTED

Prepared by: Leland Snook

DIRECT TESTIMONY OF JOHN STERLING

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

EXHIBIT

APS-4

ADMITTED

February 25, 2016

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DIRECT TESTIMONY OF JOHN STERLING
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Sterling, and my business address is 8737 E. Via de Commercio, Suite 220, Scottsdale, AZ 85258.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Senior Director, Research & Advisory Services at the Solar Electric Power Association (SEPA). My educational and professional experience are set forth in Attachment 1 to my testimony.

At SEPA, I am responsible for managing government grants where SEPA is either the prime or sub-contractor, as well as managing our advisory services practice that we offer to member companies. In this role I have consulted to dozens of utilities and other companies on solar strategic planning, community solar design, power procurement, and other related issues. Lastly, I have overall responsibility for SEPA's 51st State Initiative, which looks at developing long-term roadmaps to transition the electricity industry towards a future that creates equitable business models and integrated grid structures to ensure that electricity is provided safely, reliably, efficiently, affordably, and cleanly; and, to meet customer demand in the near and long term for solar and other distributed options.

Q. PLEASE BRIEFLY DESCRIBE SEPA.

A. SEPA is an educational non-profit dedicated to helping electric utilities integrate solar and other distributed energy resources into their energy portfolios in ways that benefit the utilities, their customers, and the general public. Established in 1992, SEPA now has over 530 utility and over 480 non-utility member organizations. Approximately 30 Arizona-based companies and organizations are SEPA members, including several solar developers, utilities, and government agencies.

SEPA operates under the following guiding principles:

- Utilities must be a critical part of the equation for solar and distributed energy resources to live up to their full potential in serving the public good;
- The long term economic health of utilities, technology companies, and their customers will be strengthened through partnership;
- The regulatory compact must evolve to support utility business models that encourage both central station and distributed energy resource deployment; and,
- Upgrades and advancements are needed to grid infrastructure, enabling technologies, and grid operations in order for solar and distributed energy resources to reach maximum potential.

II. <u>SUMMARY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. In 2014 and 2015, I served as the stakeholder facilitator for a working group created by Tennessee Valley Authority (TVA). This working group's purpose was to provide input and feedback on the creation of a methodology to calculate the value (defined as the net of benefits and costs) of different distributed generation resources on the TVA system. Specifically, this group focused on distributed solar as the first technology under consideration. The purpose of my testimony is to present the conclusions of the working group and discuss the components of the methodology that was agreed upon. SEPA is not an advocacy organization and does not engage in advocacy discussions. Consequently, my testimony is not meant to convey a preferred approach; rather, it is meant to provide additional information regarding the benefits and costs of distributed solar as determined by the TVA working group. This testimony is meant to serve as a reference point for the Arizona Corporation Commission.

III. <u>BACKGROUND ON THE INITIATIVE</u>

Q. PLEASE DESCRIBE TVA'S ROLE IN THEIR REGION.

A. TVA is an agency of the United States that provides generation and transmission to 155 local power companies (LPCs) and business customers in parts of seven southeastern states. Through those LPCs, which includes both cooperative and public power utilities, and their direct-serve customers, TVA ultimately provides energy for 9 million people. Under their agreements with the LPCs, TVA is the sole generation provider.

Q. HOW DID TVA HISTORICALLY FACILITATE DISTRIBUTED SOLAR TRANSACTIONS?

A. TVA has had a legacy solar program for several years that was developed to stimulate solar deployment via high incentive payments. These incentives stepped down over time and were scheduled to reach retail level at the end of 2015. The LPC community could voluntarily participate in this program, and over 130 of the 155 LPCs chose to do so. Because of TVA's power contract requirements, whenever a customer chose to go solar and participate in the program a tri-party agreement would be entered into. The system would receive a separate production meter and TVA purchased 100% of the generation from the customer at the retail rate plus the then-applicable incentive.

Q. WHAT WAS THE IMPETUS BEHIND THE TVA WORKING GROUP?

A. TVA's solar incentive program was scheduled to phase out at the end of 2015. Coupled with this, there was a growing recognition that understanding the true benefits and costs from these types of resources would be beneficial to all market participants, especially since TVA was also about to go through the creation of a new Integrated Resource Plan

(IRP). As part of the IRP initiative, a stakeholder group had been created to provide context and feedback on how various renewable resources should be treated from a modeling perspective. TVA decided to bring together a subset of that broader stakeholder group and create a discussion around the benefits and costs of distributed generation, and (in particular) distributed solar. This initiative was dubbed distributed generation – integrated value (DG-IV).

Q. WHAT TYPES OF ORGANIZATIONS WERE ASKED TO PARTICIPATE IN THE DG-IV WORKING GROUP?

A. TVA assembled a diverse group of representatives from organizations that participate in the Tennessee Valley region. This included four LPCs, the Tennessee Valley Public Power Association (TVPPA), several environmentally-focused non-governmental organizations, representatives from the local solar industry, two state government organizations, and two national research groups, including one national lab. SEPA was asked to serve as an independent third-party facilitator and subject-matter expert. In addition, the Electric Power Research Institute (EPRI) took a lead role in analyzing distribution system impacts. In total, 14 organizations were brought to the table.

Q. HOW DID YOU DEFINE "VALUE STREAMS" TO THE WORKING GROUP?

A. We defined a value stream as the *net* of the benefits and costs for a particular category of a distributed solar project's impact. To start the conversation, we specifically discussed the following value streams: avoided energy; generation capacity deferral; fixed and variable O&M; ancillary / grid support services impact; transmission system impact; distribution system impact; system losses; environmental; economic development; disaster recovery; and, security enhancement impact. Each of these was discussed in turn to provide a basic understanding of what each is intended to capture.

To ensure participants started off with a broad understanding of these types of methodologies, an overview of "value of solar" initiatives from other parts of the country, such as Austin Energy and the State of Minnesota, was provided. To provide additional context, particularly because we did not want to unduly influence the opinions of participants, we recommended three specific publicly-available reports that all stakeholders should review prior to the next meeting. Those included SEPA's "Ratemaking, Solar Value and Solar Net Energy Metering – A Primer" report, Rocky Mountain Institute's "A Review of Solar PV Benefit & Cost Studies", and "Minnesota Vale of Solar: Methodology", prepared for the Minnesota Department of Commerce by Clean Power Research. These documents were selected to provide a range of information on how different value streams were considered and subsequently calculated in other benefit / cost studies done nationally.

Q. ULTIMATELY, WHAT VALUE STREAMS WERE INCLUDED AS COMPONENTS OF THE FINAL DG-IV METHODOLOGY?

A. The final methodology includes the following value streams:

- Generation Deferral (Capital and Fixed O&M)
- Avoided Energy (Fuel, Variable O&M, and Start-up)
- Environmental (Compliance and Market)
- Transmission System Impact
- Distribution System Impact
- Losses (Transmission and Distribution)

Four components were identified as being beneficial to program design discussions that would leverage the DG-IV. Essentially, these items can be taken into consideration as part of the determination of the final price offered to customers in exchange for their solar production. Those were:

- LPC Costs & Benefits
- Economic Development
- Customer Satisfaction
- Local Differentiation

Lastly, five final components were identified as placeholder topics that should continue to be discussed in the context of the DG-IV:

- System Integration / Ancillary Services
- Additional Environmental Considerations
- Security Enhancement
- Disaster Recovery
- Technology Innovation

Q. WHAT IS THE SIGNIFICANCE OF BREAKING OUT THE ADDITIONAL TWO CATEGORIES OF COMPONENTS, SEPARATE FROM WHAT IS INCLUDED IN THE DG-IV METHODOLOGY?

A. The components that are incorporated into the final methodology are all currently quantifiable value streams that impact TVA and its LPCs directly and the working group agreed they should be valued as such. The additional two categories did not have universal consensus on inclusion; however, there were merits to the arguments behind their consideration and those arguments could be leveraged in subsequent conversations on how to design a program for distributed solar customers going forward.

One fact that bears mentioning is that TVA was up front telling the stakeholders that the ultimate numerical value that is calculated at the end of the process may or may not be high enough to cause a solar transaction in the region; however, that number would be very informative to everyone involved moving forward. A program would still need to get designed that leveraged the conversations around DG-IV, but recognized the need to create an ongoing solar market.

Q. PLEASE DESCRIBE HOW THE GENERATION DEFERRAL CALCULATION WAS DETERMINED.

A. The working group reached consensus on leveraging TVA's Capacity Expansion Model (CEM) that is run in support of the IRP process to determine generation capacity deferral, as well as fixed O&M. The CEM is a detailed resource planning tool that analyzes a variety of different potential resource decisions to determine the optimal capacity build-out to meet future needs. For this process, the group decided to take the base run that was being developed as part of the IRP, and then run a second case that considered 2,000 MW-ac of solar being added at zero cost. The model's second run resulted in a different, less expensive capacity build-out plan. Those reduced revenue requirements (compared to the base case) were then levelized to estimate the generation deferral value.

Q. DID THE STAKEHOLDERS DISCUSS THE TRADEOFF BETWEEN THIS DETAILED APPROACH AND THE FACT THAT THE MODELING ITSELF IS NOT VERY TRANSPARENT?

A. Yes, that was a specific discussion point of the group. In the end, many of the same stakeholders were also engaged in the IRP process where they had the opportunity to learn about these modeling approaches and provide inputs related to capacity value and other factors. While they all recognized that other approaches that we discussed would be simpler and far more transparent, it was agreed by stakeholders that the more accurate modeling that was possible by using the CEM was preferred.

Q. WAS A SIMILAR APPROACH TAKEN FOR AVOIDED ENERGY?

A. Yes it did. The working group decided to leverage TVA's Production Cost Model (PCM), the hourly dispatch counterpart to the CEM. This detailed model considers how to most economically dispatch the series of generation resources determined out of the CEM. The same two cases mentioned previously were run in the PCM and the reduced revenue requirements related to fuel, variable O&M, and reduced start-ups became the avoided energy deferral value. Again, this is a much more detailed and less transparent approach than had been done in other initiatives, but it was the approach that was supported by the working group.

Q. DID THE ISSUE OF TRANSPARENCY COME UP AFTER THE WORKING GROUP DETERMINED TO LEVERAGE THE CEM AND PCM FOR MODELING?

A. Yes, it did. During two additional meetings, significant time was allotted to make sure all stakeholders had an understanding of how these models worked and how the results were generated.

Q. PLEASE DESCRIBE HOW TRANSMISSION VALUE WAS DETERMINED.

TVA developed a series of transmission impact case studies, based on actual system conditions, which would create positive, negative, and neutral impacts from adding solar at a specific location. After reviewing this approach, one stakeholder suggested an alternative; namely, that TVA leverage its point-to-point transmission service rate as a proxy for the reduced usage on the transmission system from distributed solar. This rate was applied to monthly peak load factors to create the avoided transmission capacity value. This proposal was adopted by the working group. Interestingly, the final values from TVA's initial proposal and from the stakeholder's alternative were very similar; however, the stakeholder approach was much simpler to both calculate and understand, leading to the decision to adopt it.

Q. PLEASE DESCRIBE HOW DISTRIBUTION IMPACT VALUE WAS DETERMINED.

A. As mentioned previously, EPRI was brought in to conduct the analytics related to distribution system impact. During this process, they conducted a detailed technical analysis for two feeders within the Tennessee Valley, and conducted a financial impact analysis for each. Those two feeders were chosen from a set of sixteen that were representative of feeders common to the region. From those, five feeders were chosen for a hosting capacity analysis. Two of these five were then chosen to compute example results, based on the penetration of 500 kW of solar on each feeder. EPRI chose this amount, as it would be the approximate penetration on an average feeder that 2,000

MW-ac of distributed solar would cause. In that sense, they attempted to align their work with the CEM and PCM modeling process.

During this analysis, EPRI reviewed the impacts to: distribution capacity (the potential to defer capacity upgrades and equipment life); voltage (whether or not there were voltage deviations or regulation issues); protection (impacts to fault current along with mitigation options); losses; and, impacts to energy consumption (due to higher delivery voltages). A net financial impacts analysis was then completed.

Q. WHAT WERE THE RESULTS OF THAT WORK?

A. EPRI's analysis did not reveal meaningful system benefits being observed, and they showed a range of potential costs. Essentially, the feeders were not capacity constrained for the foreseeable future under today's planned growth assumptions, so benefits in the form of capacity deferral did not materialize. One of the two feeders did require mitigation to address voltage issues that arose at that level of solar penetration.

Q. HOW DID THE TVA WORKING GROUP DECIDE TO TREAT DISTRIBUTION SYSTEM IMPACT?

A. Ultimately, the decision was made to include the value stream at 0 cents per kWh. The working group agreed that further study was needed on this issue.

Q. PLEASE DESCRIBE THE APPROACH TO CALCULATING SYSTEM LOSSES.

A. System losses were broken down into two different buckets: transmission losses and distribution losses.

For transmission losses, TVA analyzed all transmission buses on an individual basis via a load flow modeling analysis. This was applied to approximately 1,300 transmission substation buses, with a goal of determining the effects of solar on load pockets across the TVA transmission system. TVA modeled a 1 MW-ac system at each substation bus, which roughly matched the other working assumption of 2,000 MW-ac of solar across the system. A marginal loss analysis was conducted by comparing system losses on a peak and off peak basis with and without the solar. The average marginal loss savings experienced was then used as the transmission loss value, which was calculated at 2.6%.

Distribution losses were calculated as part of EPRI's analysis. This, too, looked at marginal impacts; however, EPRI also took into account that localized energy consumption would increase due to higher voltages. The net impact of the reduced losses compared to the increase in consumption from higher voltage became the distribution loss value, which was calculated at 1.6%. That value was the mid-point for the two feeders that EPRI analyzed.

Q. PLEASE DESCRIBE THE DISCUSSION SURROUNDING ENVIRONMENTAL VALUE.

A. Environmental impact was the single most discussed value stream in the process, with a variety of viewpoints shared. TVA presented an environmental impact value that was calculated from its PCM run. This leveraged TVA's price curve for CO_2 that was being used in its IRP process. TVA showed annual data including costs and tons reduced by adding the 2,000 MW-ac of solar. In response to this, several stakeholders proposed using the social cost of carbon as had been done in the State of Minnesota. Alternatively, they suggested using voluntary Solar Renewable Energy Credit (SREC) market pricing until such time as TVA's CO_2 curve took effect.

After a thorough debate across several meetings about the different methods and components that could be leveraged in a valuation methodology, TVA proposed a solution that represented a compromise of positions. This solution was ultimately adopted with consensus support.

Q. WHAT WAS THE PROPOSED SOLUTION?

A. The environmental impact discussion would be broken down into three buckets: Environmental Compliance Value, Environmental Market Value, and Additional Environmental Considerations.

Environmental Compliance Value addressed the regulatory compliance components that are incorporated into TVA's IRP process via its price curve for CO_2.

Environmental Market Value captured the market value of the SREC created by the solar resource, which was referred to during the meeting as its "opportunity cost"; that is, TVA had an opportunity to sell the SRECs into voluntary markets to monetize their value, and that value could be captured in the methodology.

Additional Environmental Considerations recognizes that additional impacts may be appropriate to consider from a broader, regional perspective (including qualitative impacts from carbon, common pollutants, and water utilization).

The working group agreed that the first two components were to be valued and included in the methodology immediately and that Additional Environmental Considerations would be depicted as a range and leveraged in the future during program design discussions.

Q. DID THE TVA WORKING GROUP COME TO ANY OTHER AGREEMENTS RELATED TO ENVIRONMENTAL IMPACT?

A. Yes. Because the conversations surrounding the environmental impact value were so robust, the working group unanimously agreed that the final document that presented the methodology should adequately represent all arguments that were presented during our stakeholder process. To that end, TVA worked to include language crafted by specific stakeholders into the final document so that their viewpoints were accurately represented. TVA also lists as reference materials many documents provided by working group participants related to the differing viewpoints on environmental impact.

Q. HOW DO ALL OF THESE COMPONENTS COME TOGETHER?

A. The formula for developing the DG-IV is as follows: (G + E + ENVC + T + D) * (1 + TL + DL) + ENVM

Where:

- G = Generation Deferral
- E = Avoided Energy
- ENVC = Environmental Compliance Value
- T = Transmission System Impact
- D = Distribution System Impact
- TL = Transmission Losses
- DL = Distribution System Losses
- ENVM = Environmental Market Value

All values are grossed up for losses because the generation occurs at the load source, except for the Environmental Market Value. This was excluded from the loss gross-up because the SRECs are based on generation only and not system utilization.

Q. IS THIS REPORT PUBLICLY AVAILABLE?

A. Yes. This report can be accessed on TVA's website at tva.gov/dgiv.[1]

IV. <u>CONCLUSION.</u>

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[1] "Distributed Generation – Integrated Value (DG-IV): A Methodology to Value DG on the Grid" (October 2015).

ATTACHMENT JS-1

Statement of Qualifications

John Sterling

John Sterling is SEPA's Senior Director of Research and Advisory Services. He has 14 years of experience in the electric utility business. Mr. Sterling holds a Bachelor of Science degree in Finance and a Masters of Business Administration from Arizona State University.

Mr. Sterling's areas of expertise include distributed solar strategic planning and program design, community solar, stakeholder engagement, resource planning, and power procurement. Mr. Sterling has worked at SEPA for 3 years. Prior to this, he served in a variety of roles at Arizona Public Service Company and APS Energy Services for 11 years.

Mr. Sterling has authored numerous publications related to solar energy, including:

- Kaufmann, K. Pang, J. Sterling, J., & Vlahoplus, C. (2016). Postcards from Hawaii: Lessons on Grid Transformation. http://www.fortnightly.com/fortnightly/2016/02/postcards-hawaii-lessons-grid-transformation.

- Sterling, J. (2016). Time to Talk. Energy & Infrastructure. http://www.nxtbook.com/nxtbooks/phoenix/ei_2016winter/index.php#/0.

- Sterling, J. (2015). Getting Past Net Metering. Public Utilities Fortnightly. http://www.fortnightly.com/fortnightly/2015/12/getting-past-net-metering.

- Vlahoplus, C., Pang, J., Quinlan, P., & Sterling, J. (2015). Community Solar: Answers to Questions You Were Afraid to Ask. Public Utilities Fortnightly. http://www.fortnightly.com/fortnightly/2015/12/community-solar.

- Chwastyk, D., & Sterling, J. (2015). Community Solar Program Design Models. Solar Electric Power Association. http://www.solarelectricpower.org/media/422096/community-solar-design-plan_web.pdf.

- Sterling, J., Davidovich, T., Cory, K., Aznar, A., & McLaren, J. (2015). The Flexible Solar Utility: Preparing for Solar's Impacts to Utility Planning and Operations. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy15osti/64586.pdf.

- Joe, B., Hong, M., & Sterling, J. (2015). Impact of High Solar and Energy Storage Levels on Wholesale Power Markets. Black & Veatch and the Solar Electric Power Association. https://pages.bv.com/SolarandEnergyStorageImpacts.html.

- Taylor, M., McLaren, J., Cory, K., Davidovich, T., Sterling, J., & Makhyoun, M. (2015). Value of Solar: Program Design and Implementation Considerations. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy15osti/62361.pdf.

- Davidovich, T., & Sterling, J. (2015). Unlocking the Opportunity in Smart Inverters. Electric Perspectives. http://mydigimag.rrd.com/publication/frame.php?i=241464&p=&pn=&ver=flex.

- Pang, J., Vlahoplus, C., Sterling, J., & Gibson, B. (2014). Germany's Energiewende: Lessons Learned for U.S. Utilities – Drawn from First-Person

Fact-Finding. Public Utilities Fortnightly. http://www.fortnightly.com/fortnightly/2014/11/germanys-energiewende.

- Davidovich, T., & Sterling, J. (2014). Unlocking Advanced Inverter Technology: Roadmap to a Future of Utility Engagement and Ownership. Solar Electric Power Association. http://www.solarelectricpower.org/unlocking-advanced-inverter-functionality.aspx.

- Sterling, J., McLaren, J., Taylor, M., & Cory, K. (2013). Treatment of Solar Generation in Electric Utility Resource Planning. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy14osti/60047.pdf.

DIRECT TESTIMONY OF BRADLEY J. ALBERT

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

February 25, 2016

EXHIBIT

APS-5

ADMITTED

Table of Contents

DIRECT TESTIMONY OF BRADLEY J. ALBERT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Brad Albert. I currently serve as the General Manager – Resource Management for APS. In this position, I have responsibility for overseeing the Company's energy commodity trading activities, long-term resource acquisition, fuel supplies, and fuel transportation.

Q. DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Mechanical Engineering from New Mexico State University in 1984. In 1990, I was awarded a Masters of Business Administration degree from Arizona State University.

I began my career with APS in 1984. In the almost 32 years that I have been with the company, I have served in various management and individual contributor roles in resource planning, energy trading, wholesale transaction structuring and pricing, risk management, and nuclear power plant licensing.

II. SUMMARY OF TESTIMONY

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. A major focus of this proceeding is estimating the value of residential distributed solar photovoltaic systems or rooftop solar. My testimony provides several methods for calculating the value of rooftop solar. Although these methodologies differ in several respects, the ultimate reason for conducting these types of analyses is to inform policy decisions regarding rooftop solar.

Retail rates must be based on actual costs and the application of cost of service principles, as discussed by APS witness Snook. However, a Value of Solar (VOS) calculation can play a valuable role for policy makers. The VOS can inform resource planning decisions and can be used to evaluate and even establish how rooftop solar is incentivized. For example, the Commission can consider the VOS in determining the amount paid to customers who export energy to the grid from their rooftop solar systems. The Commission could also use the VOS to establish additional transparent incentives, such as the up-front cash incentive that the Commission authorized for a period of time.

Q. PLEASE SUMMARIZE THE MAIN POINTS OF YOUR TESTIMONY.

A. In my testimony, I present three different VOS methodologies:

- **Short-term avoided cost.** This would set a value for energy produced by rooftop solar based on reported market prices.
- **Long-term avoided cost.** This would begin with the methodology used in APS's 2013 SAIC study, with modifications that reflect additional information regarding system operations that APS has obtained since the SAIC study was conducted.
- **Adjusted grid-scale cost.** This methodology begins with a reported power purchase agreement (PPA) price for a grid-scale solar project, appropriately selected based on geography, timing, and other relevant factors. The

methodology then adjusts the grid-scale PPA price to account for real operational differences between grid-scale and rooftop solar applications.

These methodologies reflect the full range of appropriate values for rooftop solar. The short-term avoided cost method is at the lower end of the spectrum, and would provide less incentives to rooftop solar. However, it would reduce costs for all of APS's customers and is largely reflective of the cost that would have been incurred to replace the actual rooftop solar production with other power sources.

The long-term avoided cost and adjusted grid-scale cost are at the higher end of the spectrum, and would provide more rooftop solar incentives, but would also result in all other non-solar customers paying higher rates.

A benefit of both the short-term avoided cost method and the adjusted grid-scale methods is that they are both derived from competitive market sources. The short-term avoided cost method uses realized wholesale market energy prices while the adjusted grid-scale uses actual reported prices for grid-scale PPAs.

It is within the Commission's discretion to choose which methodology to adopt for determining the VOS. Based on the nature of the calculation, however, it appears that the price paid for a grid-scale solar PPA should be the ceiling for any VOS, after appropriate adjustments are made to reflect the operational differences between grid-scale and rooftop solar applications. Because both rooftop and grid-scale solar applications contribute the same benefits to the system, the goal should be to reduce costs to customers by obtaining those benefits for the least amount of money.

III. DESCRIPTION OF "VALUE OF SOLAR"

Q. DESCRIBE WHAT IS MEANT BY THE TERM "VALUE OF SOLAR."

A. Rooftop solar is simply another source of energy generation on APS' electric system. The APS electric system is comprised of many different sources of electric generation, each with its own characteristics like size, fuel source, responsiveness to dispatch control, etc. Solar generation is produced in many forms in the APS system including through heat generated by the sun (e.g., the Solana Generating Station near Gila Bend), larger "grid-scale" photovoltaic (PV) arrays that track the sun as it crosses the sky, and other fixed-position PV systems connected to the grid in other large arrays or on buildings throughout our service territory. Rooftop solar typically is associated with installations similar to the last example and are most commonly smaller scale, fixed position PV arrays built on customer homes and businesses. In the context of this case, the term "value of solar" refers to the value that the electric system receives from rooftop solar. Some of these benefits can be quantified and result in measurable cost savings to the electric system. For example, one can measure the cost savings of rooftop solar by how much it would have cost to produce the same amount of electricity from APS' other electric generation sources or, in some cases, to acquire low cost power in the wholesale market. Other purported benefits are difficult to quantify and don't result in a direct cost savings to the utility or utility customers.

Q. WHAT ARE SOME OF THE DIFFERENT WAYS TO CALCULATE THE "VALUE OF SOLAR"?

A. Calculations typically estimate the value of solar using either historical or prospective analyses. Using an historical perspective, for example, we could look at the rooftop solar electricity production yesterday and calculate how much it would have cost to either generate or purchase this electricity from other available sources. For this type of analysis, the inputs to the calculation are known — total customer demand, actual fuel prices, timing and availability of the resource, actual wholesale electricity market prices, etc.

Prospective analyses forecast the future benefits of a resource, relying on a set of assumptions, such as future customer demand growth, future fuel prices, cost, timing, availability and performance of alternative electric generation technologies, etc.

A third way to calculate the value of solar would be to estimate the cost of deploying solar PV technology at a grid-scale to achieve similar benefits.

Q. HOW SHOULD LONG-TERM ESTIMATES OF THE "VALUE OF SOLAR" BE USED?

A. To provide reliable and cost-effective service to customers, electric utilities make investments in assets with relatively long lives. For example, APS currently has generating plants that are providing service to our customers more than 40 years after they were initially placed into service. The initial decisions to make these long-lived investment decisions required the development of cost and value estimates that match the expected lifetime of the asset. Calculating the future value of solar is a function of resource planning and plays an important role in facilitating these types of long-range resource planning decisions.

Q. CAN YOU DIFFERENTIATE BETWEEN THE VALUE THAT AN INDIVIDUAL ROOFTOP SOLAR CUSTOMER RECEIVES VERSUS THE ELECTRIC SYSTEM "VALUE OF SOLAR"?

A. This is an important distinction. The "value" from the customer's perspective is the customer's net savings, versus not installing the rooftop solar system and receiving all of their electricity service from APS. There are also environmental benefits the customer might personally ascribe to the rooftop solar system.

Residential customers with rooftop solar systems have no incentive to minimize the overall cost of electricity production. Instead, they want to minimize their total cost of electricity service: the monthly bill they receive for service from APS, based on APS's tariff structure and net metering policies, plus the cost of owning or leasing the rooftop solar system.

Contrast this with the electric utility's perspective. APS' regulatory responsibility is to provide highly reliable electricity service to all of our customers at affordable prices. All other things being equal, our value of solar perspective must be based upon the cost of replacing the electricity produced by rooftop solar with other available production sources at the lowest possible cost. If a regulator mandates that environmental attributes are included in the valuation, the utility perspective is to obtain those attributes at the lowest possible cost for the benefit of all customers.

IV. <u>"VALUE OF SOLAR" ATTRIBUTES</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST AND BENEFIT CATEGORIES OF ROOFTOP SOLAR REFERENCED IN CHAIRMAN LITTLE'S DECEMBER 22, 2015 LETTER.

A. In a December 22, 2015 letter to this docket, Chairman Little identified seven cost and benefit categories that should be addressed in this proceeding. They are:

1. Utility distributed solar costs, including incentive program, system integration cost, and utility revenue losses;

2. Energy generation savings;

3. Generation capacity savings;

4. Transmission capacity savings;

5. Distribution capacity savings;

6. Environmental benefits; and,

7. Economic development benefits.

APS witness Leland Snook discusses the cost of providing service to rooftop solar customers, which addresses the lost utility revenues, and APS witness Ashley Brown addresses the economic development benefits.

Q. ARE THERE OTHER COST AND BENEFIT CATEGORIES NOT INCLUDED IN THE SEVEN MENTIONED IN CHAIRMAN LITTLE'S LETTER?

A. Yes. Within my testimony, I discuss several other categories that are relevant to VOS, such as system-integration costs and curtailability.

Q. PLEASE DESCRIBE ENERGY GENERATION SAVINGS.

A. A rooftop solar system is a small-scale power production facility. The energy produced by this small-scale generator displaces energy that would have otherwise been produced by either another one of APS' generating units or by purchasing the energy from another entity in the wholesale market — if that is more cost-effective at the time.

The energy generation savings or "energy value" of the rooftop solar represents the cost the utility would have incurred if the energy had been produced/procured from another source by the utility. This energy value shows up in the form of fuel and purchased power cost savings — i.e., APS's overall fuel and purchased power expenses are lower by the amount of these energy value savings — which are passed through to customers via the Power Supply Adjustor (PSA) mechanism.

Q. IS THE ENERGY VALUE LIKELY TO CHANGE AS MORE ROOFTOP SOLAR IS ADDED?

A. Yes. Assuming that other variables remain constant, my expectation would be that the energy value will continue to decline with higher penetration levels of rooftop solar. As the penetration continues to increase, the rooftop solar production will displace even lower-cost production sources on the APS system. It will also lead to more start-stop cycles on conventional generating units that will be required to reliably meet customer demand during the time periods when rooftop solar is not capable of producing energy. These start-stop cycles increase the maintenance requirements on the conventional generating units which increases costs.

Q. SHOULD THE ENERGY GENERATION SAVINGS INCLUDE ENERGY LOSSES?

A. Yes. Whether they are included as part of energy generation savings, or accounted for separately, energy losses nonetheless merit discussion. However, it is important to recognize that there are new questions that have been raised within the industry regarding the magnitude of energy-loss savings when other impacts are also considered. I elaborate further on this question in a later section of my testimony.

Q. PLEASE DESCRIBE ENERGY LOSSES.

A. Energy losses occur as electricity is transmitted across the grid. A portion of the electricity produced by a remotely-located power plant is lost as that electricity moves across the transmission and distribution system before arriving at the customer's premises. Because of this, there is an advantage to having generation sources like rooftop solar that are located at the customer's premises. To the extent that this energy is consumed at the same site, energy losses are reduced because this power does not have to travel across the grid before arriving where it will be consumed.

Q. PLEASE DESCRIBE GENERATION CAPACITY SAVINGS.

A. A central tenet of electric utility resource planning and operations is to have sufficient generating capacity to reliably meet customer demand at all times. This means the utility must have sufficient generating capacity to meet expected customer demand at the instant of highest customer demand — referred to as peak demand — and at all other times of the year.

For APS, these occurrences of highest customer demand typically occur between the hours of 5 p.m. and 6 p.m. on hot summer afternoons during July or August. This need for generating capacity to meet peak demand drives generation costs — both significant capital investment decisions and purchase commitments to use generating capacity owned by other companies.

It is also important to understand that the utility must have sufficient capacity to reliably meet customer demand during all hours of the year. On the peak customer demand day of the year and on many other hot summer days, the hours immediately following the daily peak demand hour are also likely to be among the highest customer demand hours of the year. Rooftop solar production during these hours is likely to be even less than at the time of the peak because it is closer to nighttime. All of these factors must be considered in determining the generating capacity value of rooftop solar.

From a resource planning perspective, the question of generation capacity value revolves around how much rooftop solar contributes during the peak customer demand period. The degree of contribution affects APS's decisions regarding future generating capacity resources. Another important consideration is that the capacity value provided by solar PV declines as more is installed on the system.

Q. CAN YOU EXPLAIN WHY THE GENERATION CAPACITY VALUE REALIZED FROM ROOFTOP SOLAR WILL CONTINUE TO DECLINE AS MORE OF IT IS INSTALLED ON THE SYSTEM?

A. The generation capacity value of rooftop solar will continue to decline as more of it is added. APS has typically experienced peak customer demand at around 5 p.m. on a hot summer afternoon. However, the hours immediately after this are also very high customer-demand periods.

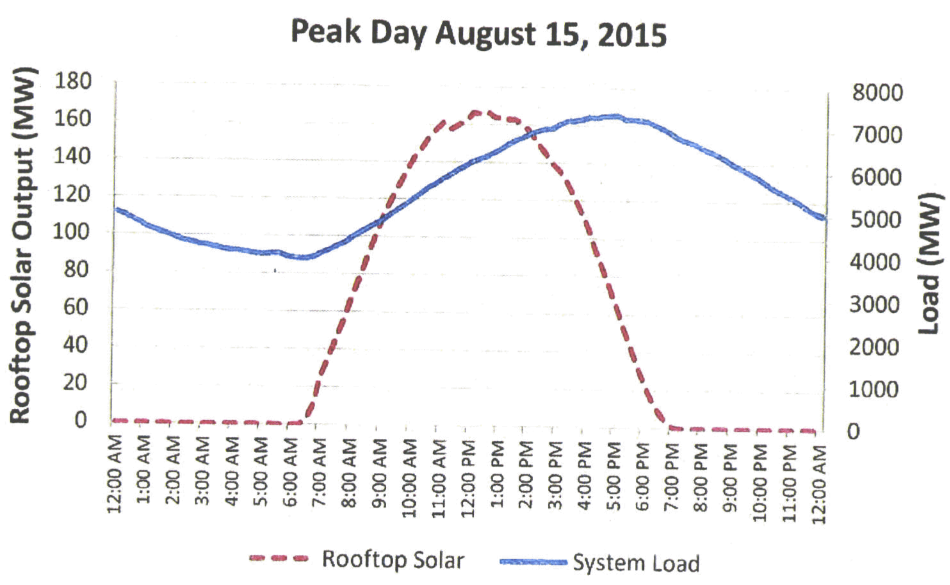
While increasing amounts of rooftop solar may continue to decrease the need for generation capacity during the 5 p.m. hour by the amount of energy that rooftop solar is producing at that time, it has less contribution during the nighttime hours that follow. Therefore, utility planners are beginning to plan for a customer peak demand occurring at 6 p.m. or even later if enough rooftop solar is added to the system. Said another way, as APS's customer base continues to grow, so does the peak customer demand. Additional rooftop solar may help mitigate the system demand up to and around the 5 pm hour, but nothing changes the fact that the sun will set and it will still be hot. Thus, after sunset, the demand for energy from rooftop solar customers and from non-solar customers will continue to drive a higher peak demand later in the early evening. As this peak demand time period is pushed to later in the evening, rooftop solar will have less and less impact on the generation capacity needed to meet peak customer demand.

Figure 1 illustrates this point. The graph shows rooftop solar production and overall customer load on the peak day of 2015. There are two main points to note from the graph:

- It is clear that rooftop solar production falls off rapidly at approximately the time of peak customer demand as the sun falls lower on the horizon.
- The hours immediately following the peak hour are very close in terms of total customer demand to the peak hour.

In other words, even though the instant of highest customer demand occurred while rooftop solar still produced some energy, nearly all of APS's infrastructure is still needed to serve customers only a short time later, when it is dark and rooftop solar no longer produces energy.

Figure 1.



Q. PLEASE DESCRIBE SYSTEM-INTEGRATION COSTS.

A. System-integration costs refer to costs incurred to allow for continued reliable service to customers as intermittent production sources are added to the grid. Examples of intermittent production sources include both wind generation and solar photovoltaics, whether at grid-scale or rooftop-scale. Both of these renewable resource types are intermittent sources because their production level can vary based upon how hard the wind is blowing or, for solar, with passing clouds or storm systems. Since electric utilities must — at each moment in the day — maintain a constant balance between the supply of electricity and customer demand, flexible generating resources are required that can either increase or decrease production rapidly to offset production variability from the intermittent wind and solar sources. Additional costs are incurred to have additional flexible resources on-line and capable of regulating the overall system supply/demand balance.

For the APS system, we typically use natural gas generating units to provide this regulating service. Note that for purposes of this testimony, I have limited this definition to include only the grid-level system-integration costs. There could be other integration costs that could occur at the local distribution level.

Q. PLEASE DESCRIBE TRANSMISSION & DISTRIBUTION CAPACITY SAVINGS.

A. In many ways, this is similar to the previous discussion of generation capacity value. Because rooftop solar is located at the customer's premise, it reduces the amount of power flowing on the distribution system during the times that it is producing energy. However, transmission and distribution infrastructure investment is driven largely by being able to reliably serve customer demand during peak-demand periods. Therefore, the ability of rooftop solar to provide value in replacing or deferring the need for transmission and distribution infrastructure investments is a function of how much energy is contributed during times of peak demand on the wires infrastructure. Note that this timing can be different than the overall system peak demand and is a function of the type of customers and their demand patterns on each portion of the distribution system. Given that rooftop solar is installed predominantly on residential feeders and that such feeders typically experience their peak loads either coincidentally or later than the overall system peak, little benefit to the distribution system has emerged from the deployment of rooftop solar.

A different and developing issue in this area is whether upgrades will be required to portions of the distribution system that are experiencing relatively high penetration levels of rooftop solar. APS has begun to experience high-voltage conditions on certain distribution feeders at times of the year when customer demand is low and solar energy production is high on those feeders. This could necessitate the installation of additional equipment to mitigate this condition to maintain reliable service to all customers on those feeders.

In our previous VOS study, we had identified potential transmission savings to the extent that rooftop solar deferred new generating capacity resources. Specifically, the identified savings were associated with the transmission costs incurred to interconnect new generating resources to the electric grid.

Q. PLEASE DESCRIBE THE VALUE OF ENVIRONMENTAL ATTRIBUTES.

A. Like the Palo Verde Nuclear Generating Station, renewable resources like solar and wind do not emit CO2 or other types of emissions when generating electricity. While APS and other utilities across the country are moving to a cleaner, long-term energy portfolio, the precise benefits attributable to rooftop solar of carbon-free generation are difficult, if not impossible, to quantify. Other than for wholesale energy sales into

California, APS does not currently incur a cost associated with CO2 emissions. However, APS does consider CO2 emissions and other environmental attributes in our resource planning processes. Although APS does not currently incur those costs, future regulations may impose a cost of carbon. In making resource planning decisions, APS factors in this possibility using an abundance of caution.

Q. PLEASE DESCRIBE CURTAILABILITY.

A. Curtailability refers to the ability of an electric generation source to reduce, either partially or completely, generation output in response to either market conditions or system operating conditions.

For example, there are times when wholesale energy prices are negative in the desert southwest region. When this happens, APS has the opportunity to get paid to take power from a neighboring supplier. During these times, it is advantageous to curtail output from our owned, grid-scale solar plants because we can save money for our customers by taking delivery of a less expensive source of power than our grid-scale solar plants --- but, in order to do so, must reduce the output from our grid-scale solar plants in order to "make room" for the less expensive energy. The ability to curtail these grid-scale solar plants remotely is key to capturing these savings as these solar plant sites are not staffed and these market opportunities are not always predictable. This requires having the necessary communications and control capabilities to effectuate these curtailments from the central control center.

The ability to curtail can actually increase the value of a solar PV resource by allowing APS to take advantage of cheaper power sources when they are available.

With the necessary installation of communications and control capabilities, rooftop solar could be technically capable of curtailing production in response to grid conditions. That communication equipment, however, is not being installed, nor does APS or any utility have the ownership of and therefore the "right" to control customer-owned rooftop solar.

Moreover, there is a large disincentive for customers to curtail: Curtailment means reducing actual energy production, meaning that the rooftop solar owner would be sacrificing a substantial retail bill credit under the current regulatory construct.

Q. IS IT APPROPRIATE TO FACTOR THE COST OF THE PANELS INTO THE REIMBURSEMENT RATE FOR NET METERING? IF SO, HOW?

A. As stated in the Mr. Snook's testimony, rates for rooftop solar customers should be based upon the cost of providing service to those customers. For surplus energy that is exported by the rooftop solar customer to the grid, the reimbursement rate for this energy should be informed by VOS. These reimbursement rates should not be based upon the cost of the rooftop solar customer's panels. To do so would risk exposing the non-solar customers to costs that exceed the value of the energy exported to the grid. Nonetheless, the adjusted grid-scale methodology would capture fluctuations in the cost of panels because it is based on reported market PPA prices.

Q. DOES THE DEPLOYMENT OF DG SOLAR RESULT IN A REDUCTION IN THE USE OF WATER IN ELECTRIC GENERATION? HOW SHOULD THIS BE CONSIDERED WHEN DETERMINING DG SOLAR VALUE?

Just like other externalities, rooftop solar can reduce water consumption. Whether and how these broader public benefits are reflected in utility rates or inform the amount paid for exported energy is a policy decision for the Commission. However, water reduction benefits is another example of how a value attribute provided by rooftop solar can be achieved at a lower cost to customers with grid-scale solar.

Q. ARE THERE ANY IMPORTANT LIMITATIONS ON HOW THE RESULTS OF VALUE OF SOLAR ANALYSES SHOULD BE APPLIED?

A. The VOS methodologies that I describe can be applied to either the entire output of the rooftop solar system, or only the energy exported to the grid. The ultimate VOS conclusion will be different depending on whether total production or exported energy is selected. Energy is much more likely to be exported during seasons of the year when the value of the energy is lower than the annual average. This is because APS customers typically consume substantially higher amounts of energy during the summer months when their air conditioning systems are being used and they are more likely to be able to consume the solar energy that their solar PV system is producing. Customer energy consumption is typically lower in the non-summer months and it is during these times when more surplus energy is exported to the grid. This difference in export production pattern would be important to recognize when attempting to establish the value of the exported energy.

V. OVERVIEW OF "VALUE OF SOLAR" METHODOLOGIES

Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF THE ALTERNATIVE APPROACHES TO VALUING ROOFTOP SOLAR

A. In my testimony, I describe the three ways of developing a value of rooftop solar that appropriately balance measurable value to APS's grid, the real impact rooftop solar has on APS's resource planning and system operations, and what is best for all APS customers over the long term. The three methods are:

1. Short-term avoided cost
2. Long-term avoided cost; and,
3. Grid-scale adjusted.

I describe each in turn.

VI. SHORT-TERM AVOIDED COST

Q. PLEASE DESCRIBE THE SHORT-TERM AVOIDED COST APPROACH TO VALUING ROOFTOP SOLAR.

A. The short-term avoided cost approach is based upon the avoided energy costs and energy losses in a near-term time window. For example, one could determine how much it would have cost for APS to produce or procure all of the energy produced by rooftop solar during 2015.

One of the advantages of this approach is that this calculation can use the actual production data captured from the meters installed on each of the systems. Therefore, the analysis does not rely upon a forecast of future production.

Second, the solar production can be valued based upon actual, realized wholesale energy market prices. This has the advantage of being relatively transparent while also being fairly reflective of APS' own system production costs. Therefore, the analysis does not rely upon forecasts of future fuel prices, underlying customer growth and all of the other forecast variables required to develop long-term avoided cost figures.

Also, this approach is consistent with the "historic test year" method established for setting utility rates in Arizona as described in Mr. Snook's testimony.

Q. PLEASE PROVIDE MORE DETAIL ON THE MECHANICS OF THIS VALUATION APPROACH.

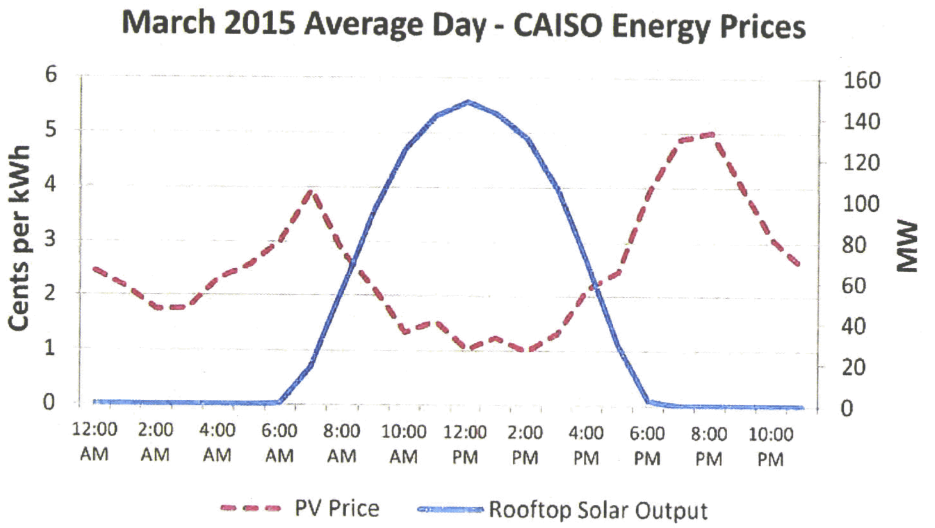
A. To illustrate this methodology, one could begin with aggregated actual rooftop solar production from the meter data for the residential systems in 2015. The meters provide production measurements for each 15-minute time segment. Then, one could use the actual wholesale market energy prices from the California Independent System Operator (CAISO) organized wholesale market to value the rooftop solar production. The CAISO market has a transaction point at the Palo Verde hub in Arizona.

APS uses this transaction point to conduct wholesale market transactions (either buy or sell) with the CAISO market. Therefore, these prices provide a good representation of the wholesale market conditions experienced in 2015 and also are a good indication of the price that APS would have paid to replace the electricity produced by rooftop solar.

It is important to note that one could select those market prices that align with the time of day that rooftop solar facilities actually provide energy. Doing so increases the accuracy of this market price analysis. Figure 2 illustrates this methodology. The graph shows average CAISO energy prices by hour for March 2015. The graph also shows the average rooftop solar production pattern by hour for the same month.

During the solar PV production periods, the CAISO energy prices were in the range of 1.0 to 2.5 cents/kwh. Additionally, the graph shows that the highest wholesale market energy prices occurred on either side of the solar PV production window. This coincides with periods of higher customer demand across the region.

Figure 2.



Q. DOES ROOFTOP SOLAR CONTRIBUTE ADDITIONAL VALUE BY AVOIDING ENERGY LOSSES?

A. Yes. An advantage of rooftop solar is that the electricity production occurs in the same place where the consumer uses the electricity. In contrast, if APS were to purchase the same electricity at the Palo Verde hub, that electricity would have to be transmitted from this wholesale market hub to the customer's premises. Energy losses of approximately 7% would be incurred in this delivery process.

Q. DOES THE SHORT-TERM AVOIDED COST APPROACH FAIL BECAUSE IT DOES NOT REFLECT LONG-TERM AVOIDED COSTS?

A. No. This criticism overlooks the fundamental difference between long-term resource commitments that a utility makes as part of a long-term resource planning and procurement process and rooftop solar. A utility procures long-term resources based on need. And once procured, a utility exercises control over the long-term resources. The utility can call on those resources when needed. And if a third-party supplier fails to perform, they pay contractual penalties.

In contrast, rooftop solar is a choice that each individual customer makes in response to their rate tariff options and prevailing net metering policy. The installed rooftop solar is not necessarily fulfilling a targeted need on the utility system. Additionally, the utility has no way of assuring that the rooftop solar system will remain available and capable of producing power over the expected life of the system.

As found by the Utah Public Utility Commission:

> Net metering generation results from a voluntary customer decision. The customers own and control their equipment, and customers make decisions about whether to install that equipment and how much capacity to install. The customer is under no obligation to maintain the system or to supply the utility with electricity. If a problem develops that prevents the customer from generating energy, the customer is under no obligation to cure it. More significantly, a customer is under no contractual obligation to provide any of the power it generates to the utility. Net metering customers may elect, at any time, to use their electricity however they choose.[1]

[1] *In re Cost and Benefits of PacifiCorp Net Metering Program*, Final Order at 13-14, Docket No. 14-035-114 (Pub. Ser. Comm'n of Utah, Nov. 10, 2015).

VII. LONG-TERM AVOIDED COST

Q. PLEASE DESCRIBE THE LONG-TERM AVOIDED COST VALUATION METHOD.

A. The long-term avoided cost approach is a resource planning methodology used by APS and others. This approach uses long-term forecasting tools to develop estimates of certain value components, such as energy, generation capacity, and energy losses. These studies are long-term in nature and are similar to studies that APS conducts to make long-term resource decisions.

Q. PLEASE DESCRIBE VALUE OF DG SOLAR STUDIES PERFORMED BY OR ON BEHALF OF APS IN THE PAST.

A. There are two significant studies undertaken on behalf of APS over the last decade. In 2009, APS engaged R. W. Beck to lead a stakeholder process to, among other things, assess the value provided by solar DE technologies in terms of both capacity and energy.[2]

This study involved more than 60 individuals representing 35 solar vendors, academic institutions, solar advocates, local builders and land developers, and solar-related construction firms as well as representatives from the regulatory community. This study developed methodologies and estimated values for generation, transmission and distribution savings that could potentially be realized under various solar DG penetration scenarios.

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[2] "Distributed Renewable Energy Operating Impacts and Valuation Study" prepared for Arizona Public Service, R.W. Beck, January 2009, page xiv.

In 2013, APS engaged SAIC, a successor of R.W. Beck, to update the values from the 2009 study and using the same peer-reviewed methodology.[3] Both of these studies were filed with the Commission.

Q. WHAT WERE THE SPECIFIC ATTRIBUTES THAT WERE VALUED IN THESE STUDIES?

A. There are five broad categories of attributes that were identified and valued in these studies:

- Distribution System
- Transmission System
- Generation System
- Fixed O&M
- Fuel, Purchased Power, Emissions & Gas Transportation

Both of these studies estimated potential values at discrete points in time,[4] and both of them used widely accepted resource planning techniques to assess value.

Q. WHAT DO YOU MEAN BY RESOURCE PLANNING TECHNIQUES?

A. By this I mean that load and resource plans were constructed for various rooftop solar penetration scenarios, and that values were determined through prospective modeling of the forecasted generation and transmission systems and their respective investment and operating costs. In other words, cases including rooftop solar were compared to a case without rooftop solar. The case without rooftop solar used conventional resources to make up for the DG in the first case. The difference between the two cases represents

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[3] 2013 Updated Solar PV Report, SAIC, May, 2009.

[4] R.W. Beck estimated values for 2010, 2015 and 2025; SAIC estimated values for 2015, 2020 and 2025.

the value of rooftop solar from a resource planning perspective. This is the methodology used in making resource decisions and is used extensively in APS's Integrated Resource Plan (IRP) filings.

Q. HAVE THESE LONG-RANGE RESOURCE PLANNING STUDIES BEEN USED TO SET RATES?

A. No, they have not. These studies are used as a tool that, at the resource planning stage, facilitate thoughtful decisions about which resources APS should procure to meet anticipated resource needs in the future. When APS conducts resource planning analyses, it updates its studies frequently. The goal is to have up-to-date analysis at the time the resource planning decision is made. Each study involves predicting values for future resources based on a number of different assumptions. Although these types of studies are not used to set rates, it is within the Commission's discretion to use these studies in establishing the amount paid for energy exported by rooftop solar systems. If the Commission were to select the long-term avoided cost methodology for this purpose, it would need to accept that the assumptions underlying the long-term projections will change and potentially change significantly. Because of this, using this methodology would cause APS's non-solar customers to inevitably pay an amount for exported solar energy that is significantly different than the actual costs avoided at the time the energy is received.

Q. WHAT SUPPLIES THE BULK OF THE VALUE IN THESE LONG-RANGE SOLAR VALUE STUDIES?

A. The vast majority of the predicted value comes from the energy produced by the rooftop solar. Rooftop solar energy production directly results in the Company consuming less fuel, buying less energy from the wholesale market, and incurring lower fuel transport costs. I generally refer to these as avoided-energy costs. In the R. W. Beck and SAIC studies, avoided-energy costs constitute between 58% and 90% of the total identified DG value.

Q. WHAT ARE YOUR OBSERVATIONS REGARDING GENERATION CAPACITY SAVINGS?

A. The second-largest value driver is related to avoided generation capacity savings. To some extent, installation of rooftop solar can defer future resource additions such as combustion turbines, along with their associated transmission, interconnection, and fixed O&M costs. Due to the diminishing capacity value of rooftop solar previously discussed, this value is limited because of the mismatch in the timing of peak rooftop solar production and the peak customer demands on APS's overall system and distribution system, and becomes less significant under high-penetration scenarios.

Q. PLEASE COMMENT ON THE DISTRIBUTION VALUES DERIVED IN THE R. W. BECK AND SAIC STUDIES.

A. In the first study, the distribution value was zero to very small, and in the second study, the value was zero. Potential distribution savings are very feeder specific. The savings depend on finding feeders that need upgrades, and that the upgrades needed can be deferred or eliminated by the addition of targeted rooftop solar. In both studies, all APS feeders were screened to determine whether the addition of rooftop solar could defer planned upgrades. The SAIC study concluded that there are an insufficient number of feeders that can defer capacity upgrades based on non-targeted rooftop solar installations to determine measurable capacity savings. Moreover, as APS obtains more data about solar penetration in its service territory, it becomes increasingly apparent that high DG penetration could lead to additional distribution costs to maintain system reliability and power quality, particularly during low customer demand periods.

Q. DID EITHER OF THESE STUDIES ACCOUNT FOR LOWER SYSTEM LOSSES THAT MAY OCCUR DUE TO SITING THE GENERATION AT THE CUSTOMER'S SITE RATHER THAN A REMOTE LOCATION?

A. Yes. Both studies captured the effects of reduced losses that may be associated with rooftop solar. Energy losses average about 7% over the course of the entire year and are estimated at approximately 12% at the time of peak demand. Both of these values are routinely factored into APS's load forecasts. To be clear, the values calculated for rooftop solar are higher than they would be otherwise because of the expected energy losses saved by reducing the need to transmit electricity from remotely located generation sources to the customer's site.

Q. IS THERE UNCERTAINTY AS TO WHETHER SOLAR DG WILL REDUCE SYSTEM LOSSES?

A. There is some discussion in the industry as to whether rooftop solar reduces or increases system losses. The logic that supports reduced losses is based on the actual mechanics of how electricity is transferred to customers. When energy is generated remotely, it goes through step-up transformers, is transmitted over long-distance transmission lines, gets transformed down to be put on the distribution system, and ultimately reduced to a voltage that customers can use. While this is an efficient means of transporting electricity over these distances, energy losses occur throughout this process. When the energy is generated locally, however, it doesn't go through this process. As a result, this logic concludes that locally generated energy avoids energy losses.

Equally valid logic supports the opposite conclusion. Rooftop solar increases voltage on the distribution feeder during certain times of the year. This higher-voltage level is a function of the quantity of energy produced by rooftop solar, and results in higher overall energy use by customers experiencing these higher-voltage conditions. The result is higher customer energy usage due to higher voltage levels.

Our previous studies have credited the value of rooftop solar with the value of the energy losses saved. However, we are actively monitoring research in this area, and the conclusions from this research could impact the results in subsequent studies. It should also be noted that equipment can be installed on distribution feeders to mitigate the high-voltage conditions caused by the rooftop solar generation. The cost of this equipment would have to be factored into the overall value proposition if it becomes necessary to mitigate the adverse impacts of rooftop solar generation.

Q. WHAT ARE THE OTHER IMPACTS OF THIS HIGH-VOLTAGE CONDITION CAUSED BY ROOFTOP SOLAR?

A. APS has begun experiencing high-voltage conditions during certain times of the year on some distribution feeders that have a high amount of rooftop solar generation relative to customer load. This condition tends to occur during times of the year in which customer demand is relatively low — during the spring time when temperatures are mild and customers are not running their air conditioning units, for example — and solar production is plentiful.

APS is actively investigating and monitoring these conditions as they can result in voltage conditions that are above specification for the feeder, trip rooftop solar systems off-line due to exceeding equipment protection setpoints, and have adverse impacts on customers. At some point, APS may need to install new equipment on the impacted distribution feeders to mitigate these high-voltage conditions.

Q. DOES ROOFTOP SOLAR DEPLOYMENT CHANGE THE NEED FOR NEW TRANSMISSION SYSTEM CAPACITY?

A. This question has been addressed in the previous R.W. Beck and SAIC studies. In both studies, the analysis did not identify opportunities to reduce planned upgrades to the transmission system. However, they did identify that transmission system upgrades needed to support incremental generation-capacity additions, sometimes referred to as interconnection costs, could be deferred to the extent that rooftop solar defers the need for incremental generation capacity additions.

Similarly, in the recently completed study in support of the Biennial Transmission Assessment (BTA) process, APS did not identify significant savings from forecasted future energy efficiency and DG additions. It should be noted that approximately 80% of the peak load reduction forecast for this analysis was due to energy efficiency and not DG.[5]

Q. PLEASE DISCUSS THE KEY DRIVERS OF SOLAR DG VALUE WHEN CALCULATED IN A PROSPECTIVE MANNER SUCH AS THAT USED IN THE AFOREMENTIONED STUDIES.

A. The largest value drivers are the cost of avoided energy production — largely driven by natural gas prices and solar penetration levels. Lesser drivers include the ability to defer new generating capacity and the cost of these resources.

Q. HAS THE OUTLOOK FOR ANY OF THESE DRIVERS CHANGED SIGNIFICANTLY SINCE THE R.W. BECK AND SAIC STUDIES WERE PERFORMED?

A. Yes, they have. The primary variables that have changed since the SAIC 2013 study are APS's load and resource forecast, fuel prices, market prices, rooftop solar penetration, and the cost and timing of APS's need for new generated capacity. Each of these variables has changed significantly and thus the long-range value predicted by this methodology has also changed significantly since 2013.

This propensity for change is a primary reason why long-range value studies should be used for resource planning, and not rate setting. Studies based on variable and unknown

[5] Technical Study, Effects of Distributed Generation and Energy Efficiency on Future Transmission Needs, filed by APS in Docket No. E-00000D-15-0001 (January 29, 2016).

factors such as fuel prices and customer behavior can produce significantly different values from one year to the next.

Q. ARE THERE LIMITATIONS TO THE APPLICABILITY OF THIS TYPE OF ANALYSIS?

A. Yes. The long-term avoided cost calculation should be based upon the least-cost manner in which the utility can achieve the same benefits. This is consistent with the utility least-cost planning philosophy. A grid-scale solar PV project can achieve similar benefits as rooftop solar, especially if adjustments are made for the operational differences as described below. Because a grid-scale solar PV project can achieve similar benefits as rooftop solar projects, the adjusted PPA price for a grid-scale solar project should be the ceiling for any value ascribed to rooftop solar.

VIII. <u>GRID-SCALE ADJUSTED METHODOLOGY</u>

Q. PLEASE DESCRIBE THE GRID-SCALE ADJUSTED VALUATION METHOD.

A. The third solar valuation approach begins with the recognition that both rooftop solar and grid-scale applications use the same basic technology — solar photovoltaic (PV) panels. Although they rely on the same basic technology, they apply this technology in different ways.

The first is related to scale. A typical grid-scale application for APS is in the 15-20 MW (15,000 to 20,000 kW) size range. By contrast, an average rooftop solar system is approximately 7 kW in size. The second main difference is that APS typically employs tracking technology on its grid-scale systems. The tracking technology allows the solar PV panels to track, and thus be pointed toward, the sun throughout the day. This tracking maximizes energy production and provides greater capacity contribution at the times of peak customer demand.

Rooftop solar systems, on the other hand, are mounted in a fixed position on the customer's rooftop. Their orientation relative to the sun depends entirely upon the orientation of the customer's roof. Because a residential rooftop system does not track the sun, it produces significantly less energy throughout the day, and produces less energy at the time of peak customer demand than a grid-scale solar PV facility.

The third difference is that grid-scale applications are selected through competitive procurement processes to ensure that APS customers receive the best deal at the time that the procurement decision is made.

A fourth difference was mentioned previously in my testimony. Grid-scale solar PV systems can be curtailed at times when wholesale market prices are negative. This curtailability increases the value of grid-scale relative to rooftop solar.

Due to these differences, grid-scale PV provides a more cost-effective means to acquire solar PV. At the same time, grid-scale PV also captures the value rooftop solar provides in relation to conventional generation. For instance, the environmental and energy benefits derived from rooftop solar can also be obtained from grid-scale solar PV systems. The grid-scale methodology is a market-based method. As such, it does not depend upon long-term forecasting assumptions like the long-term avoided cost methodology does.

Recognizing that the generating technology is the same, and that they both bring similar value to the system, albeit at different cost, the gid-scale adjusted methodology starts by deriving the current market price for grid-scale solar PV long-term power purchase agreements (PPA) from industry-reported transactions. This grid-scale PPA price is them adjusted for recognized valuation differences between grid-scale and rooftop solar, each of which is described below. The resulting adjusted grid-scale value would represent the cost at which the utility could realize the same value attributes that rooftop solar systems supply.

Q. PLEASE EXPLAIN THE BENEFITS OF USING THIS METHODOLOGY.

A. This methodology is based on the measurable cost of grid scale solar PV based on actual market pricing. Because the same basic solar PV technology is used with both grid-scale and rooftop solar PV, they deliver the same hard benefits and the same soft, or difficult-to-quantify, benefits. This approach avoids the controversial topic of how to value the difficult-to-quantify attributes such as environmental emissions, societal health benefits, or market-price mitigation. To the extent that these value attributes contribute value to rooftop solar, they are similarly obtained through either grid-scale or rooftop applications. The benefits that apply to both technologies become irrelevant, so we only need to focus on the differences. In short, there may be differences between capacity value, energy value, T&D benefits, system losses, and curtailment.

Q. PLEASE EXPLAIN THE COST OF GRID SCALE PV.

A. There are several ways that the cost of grid-scale solar PV can be determined. It could be based on quotes that APS obtains from conducting RFPs, or from publicly available costs of solar energy acquired by other utilities in the region. The advantage of this is that it is based on information that is known with certainty today, and not based on projections of value that may or may not materialize in the future. With this methodology, a PPA price should be selected from information regarding grid-scale for solar PV projects in regions that are likely to have similar solar conditions to Arizona.

Q. PLEASE EXPLAIN THE ENERGY LOSSES ADJUSTMENT.

A. The PPA price that forms the starting point for the valuation should be increased to reflect energy losses avoided by rooftop solar. APS experiences an average of 7% energy losses on its system over the course of a year. Under this methodology, the PPA price should be increased by 7% for rooftop solar installed on APS's system.

Q. BECAUSE ROOFTOP SOLAR DOES NOT REDUCE OR AVOID DISTRIBUTION FACILITIES, SHOULD THE CORRESPONDING ADJUSTMENT BE ZERO?

A. Yes. In both the R.W. Beck and SAIC studies, we went through a sophisticated and time-consuming process to estimate savings that may occur on the distribution system due to the presence of rooftop solar. In those cases, we identified zero to very small potential distribution savings that could occur as a result of high levels of rooftop solar. And in fact, rooftop solar may increase the need for distribution investments. If this were to be studied more, the developing investigations into rooftop solar requiring distribution upgrades would need to be considered.

Q. PLEASE EXPLAIN THE TRANSMISSION SYSTEM ADJUSTMENTS.

A. In our previous studies, we did not find significant transmission system deferral opportunities resulting from rooftop solar. What we did find is that we could defer transmission associated with peaking capacity deferrals.

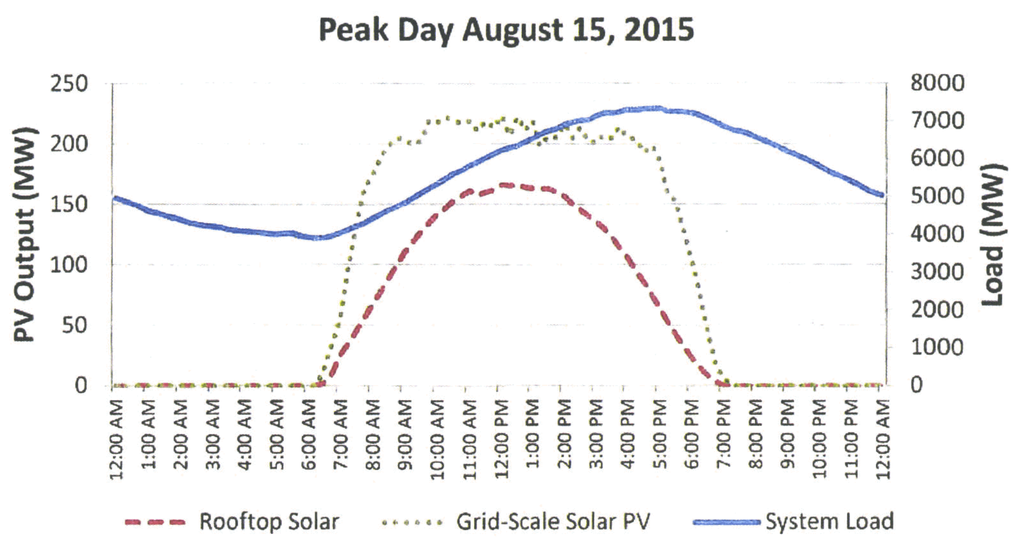
Q. PLEASE EXPLAIN GENERATION SYSTEM VALUE ADJUSTMENT.

A. As described previously, the grid-scale applications employ single-axis tracking technology that allows these systems to produce more energy during the late-afternoon / early-evening time period which better coincides with overall customer peak demand.

This adjustment should reflect the resulting capacity value difference between grid-scale and rooftop solar PV.

Figure 3 illustrates the difference between rooftop solar and grid-scale production during the peak season. The graph clearly shows the higher contribution of grid-scale PV during the specific timeframe when customer demand is at its highest.

Figure 3.



Q. PLEASE EXPLAIN THE ENERGY VALUE ADJUSTMENT.

A. Similar to the explanation of the Generation System Value Adjustment, because grid scale PV produces more power late in the afternoon when it is more valuable, there is an energy value adjustment. To establish the value of this difference, we could compare the value of grid scale PV and rooftop solar using actual market prices and production profiles of grid scale and rooftop solar.

Q. PLEASE DESCRIBE THE CURTAILMENT ADJUSTMENT.

A. As previously described, the market has changed significantly due to the vast amount of solar generation being put onto the grid in our neighboring state of California. In 2015, there were a significant number of hours of the year in which the market price of electricity was negative. With the ability to curtail power plant operations, APS's customers can benefit by APS being paid to receive energy from the market during these times. APS has the ability to curtail grid-scale PV operations during these negative market-price hours. APS does not, however, have this ability with rooftop solar. Again, we could use 2015 actual market prices and grid scale and rooftop solar production profiles to calculate the additional value of grid-scale due to the ability to curtail.

Q. WHAT ARE THE ADVANTAGES OF USING THIS METHODOLOGY?

A. Based upon the prudent utility planning principles that have been a basic premise upon which utility resource procurement decisions have historically been made, a utility has an obligation to seek out the lowest-cost, best-fit approach to fulfilling a resource need. The grid-scale adjusted methodology is consistent with this principle in that it identifies the lowest-cost, best-fit manner of achieving the same resource value.

IX. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Under present net metering policy, rooftop solar customers effectively receive the full retail rate for the energy they export to the grid. APS's retail rate, however, reflects the entire cost to provide electric service, of which energy is only a portion. Paying the full retail rate for energy overcompensates rooftop solar energy exports.

A VOS can be useful for important policy-making decisions. It can inform the resource planning process. It can also be used to determine the amount that should be paid to customers for energy exported to the grid from rooftop solar systems. Based on my experience, and observed operational and market data, there are three ways to establish a VOS.

The first is a short-term avoided cost, which uses actual data concerning market prices paid and rooftop solar production. The second, subject to the caveats described above, is a long-term avoided cost that uses a resource planning perspective to predict the future benefits of rooftop solar. The third is an adjusted grid-scale method, which adjusts the reported price paid for a grid-scale solar PPA to account for the operational differences between grid-scale and rooftop solar applications.

Each methodology falls along a spectrum of potential values. If the same resource - energy generated using the sun - can be obtained at a cost lower than the retail rate, APS believes that all customers should only be required to pay that lower cost. Nonetheless, if the Commission decides to compensate rooftop solar energy beyond the simple energy value, grid-scale solar PV can provide the same benefits as rooftop solar at a substantially lower cost. Therefore, the excess energy from rooftop solar customers should be compensated at a rate no higher than the cost of grid-scale solar PV.

REBUTTAL TESTIMONY OF BRADLEY J. ALBERT

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

April 7, 2016

EXHIBIT

tabbies

APS-6

ADMITTED

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**REBUTTAL TESTIMONY OF BRADLEY J. ALBERT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)**

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Brad Albert. I currently serve as the General Manager – Resource Management for APS. In this position, I have responsibility for overseeing the Company's energy commodity trading activities, long-term resource acquisition, fuel supplies, and fuel transportation.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. <u>SUMMARY OF TESTIMONY</u>

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A. I first address two fundamental flaws in the analysis put forth by TASC witness Mr. R. Thomas Beach. Specifically, Mr. Beach:

1. Fails to consider that grid-scale solar can capture virtually all of the claimed solar value attributes at a fraction of the cost; and

2. Treats all energy produced by rooftop solar – both self-consumed energy and energy exported to the grid – as the same for purposes of establishing value.

I demonstrate that these flaws are so substantial that they invalidate his approach to valuing rooftop solar.

Q. PLEASE SUMMARIZE THE MAJOR FLAWS IN MR. BEACH'S PROPOSED VALUE OF SOLAR (VOS) METHODOLOGY.

A. There are two primary flaws:

- The first is that Mr. Beach fails to consider that grid-scale solar can provide virtually all of the claimed rooftop solar value attributes at a fraction of the cost. The failure to consider alternative means to obtain the same value violates one of the most basic principles of electric utility resource planning: identifying the least cost manner of meeting an identified resource need.

  Mr. Beach assumes that the lowest cost alternative means for a utility to obtain the attributes provided by exported rooftop solar energy is through construction of natural gas-fired generation and that the cost of this alternative must be adjusted to account for the fact that natural gas generation does not provide the same attributes as exported rooftop solar energy on a number of dimensions. But this approach ignores the fact that there is an alternative other than natural gas generation that can provide these same attributes at a significantly lower cost than what Mr. Beach calculates in his analysis – namely, grid-scale solar PV.

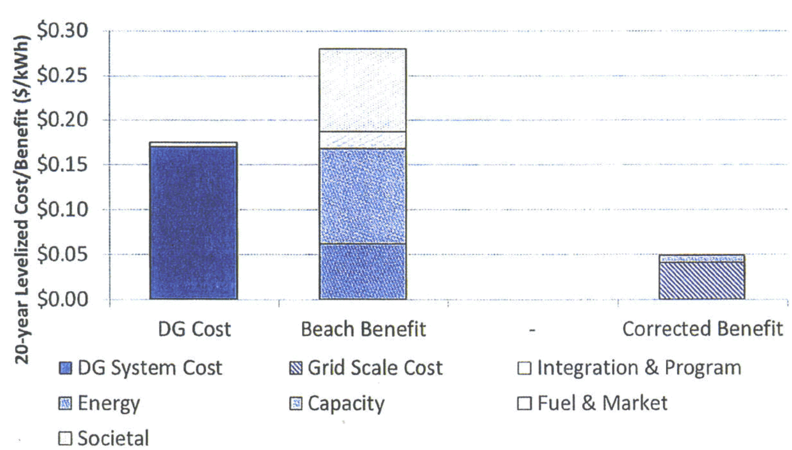
  One must ask: How can Mr. Beach's analysis represent the value of exported rooftop solar energy when his analysis is not based upon the least cost alternative? More importantly: Why should customers be compelled to buy exported rooftop solar energy at a high cost based on Mr. Beach's flawed analysis when there are far less costly ways of obtaining the solar power?

- The second is that Mr. Beach treats all energy produced by rooftop solar—both self-consumed energy and energy exported to the grid—as the same for purposes of establishing value. Mr. Beach calculates a value for the entire rooftop solar system output, and then applies that value on a per kWh basis to exported energy. Exported and self-consumed energy are not, however, the same because they occur in different proportions during different hours of the day. In particular, a small percent of exports occur during hours of peak customer demand on the APS system. A high percent of self-consumed energy occurs during those hours. This is an extremely important difference. The capacity value of any generating resource depends upon how much it generates during periods of peak customer demand. That value will be different for exported energy and self-consumed energy from rooftop solar systems. Any value of rooftop solar analysis that overlooks the differences in the time pattern of exports and self-consumption is critically flawed.

Q. PLEASE SUMMARIZE THE COMBINED EFFECT OF MR. BEACH'S TWO ERRORS.

A. The combined effect of these two errors causes a dramatic overestimation of the value of exported rooftop solar energy. Figure 1 illustrates the magnitude of Mr. Beach's analysis flaws and the impact these flaws have on his cost/benefit test results (from Figure 1 of his direct testimony). Correcting just these two obvious errors completely reverses his conclusions. Contrary to supporting the current cost paid for exported rooftop solar energy, Mr. Beach's analysis, performed correctly, should have concluded that an appropriate rate for exported rooftop solar is no more than 4.9 cents/kWh.

Figure 1 - Corrections Made to Beach Figure 1



III. GRID-SCALE SOLAR AS THE MOST COST-EFFECTIVE WAY FOR CUSTOMERS TO OBTAIN THE VALUE OF SOLAR

Q. PLEASE EXPLAIN THE IMPORTANCE OF IDENTIFYING THE LEAST COST MEANS TO OBTAIN A RESOURCE NEED.

A. Utility service inevitably involves incurring costs. But it should never be forgotten that costs incurred by utilities are ultimately paid by customers. The responsibility to carefully weigh and plan investments to avoid undue cost burdens on customers is one that APS takes very seriously.

In my role as General Manager for Resource Management, I work to ensure our procurement decisions start with a clearly identified resource need and include a robust study of the least cost method for fulfilling that resource need. It would be relatively easy to develop and implement a plan to meet a certain need without regard to cost or without assuring that the plan was the lowest reasonable cost way of meeting that need. But doing so would not be consistent with our responsibility to customers, nor with widely-recognized best practices.

The same is true for a VOS analysis. Simply establishing a value for rooftop solar attributes, without considering a full range of alternative means for obtaining those same attributes, is a woefully deficient planning and procurement process. The first step in any VOS methodology should be to identify the resource need to be fulfilled by solar. The second step should be to analyze available options for satisfying that resource need—for example, grid-scale solar, rooftop solar and conventional generation options. The value of a generating resource such as rooftop solar would be established by identifying the least cost alternative means of meeting that same resource need.

Q. DID MR. BEACH INCLUDE GRID-SCALE SOLAR IN HIS ANALYSIS?

A. No, Mr. Beach did not compare the cost of obtaining the attributes of solar with grid-scale instead of rooftop solar. He only compared the cost of obtaining these attributes with construction of natural gas-fired generation instead of rooftop solar. This is a foundational error in methodology that invalidates his conclusions.

Q. CAN YOU ESTIMATE THE MAGNITUDE OF MR. BEACH'S FAILURE TO ANALYZE GRID-SCALE SOLAR?

A. Yes, assuming Mr. Beach's other conclusions are correct, Mr. Beach would have customers pay 17.9 cents/kWh to obtain 22.4 to 26.3 cents/kWh of value, when they could pay 4.6 cents/kWh or less to obtain the same, or perhaps greater, value.

In Table 11 of Exhibit 2 of Mr. Beach's direct testimony, he summarizes the various value attributes that he ascribes to rooftop solar production (note that for ease of explanation, and without agreeing with its accuracy, I will base my example on the residential rooftop solar values from his table). Mr. Beach's combination of direct and societal benefits range in value from 24.8 to 31.1 cents/kWh. If I were to simply concede that a remotely-located grid-scale solar PV may not provide for his identified transmission and distribution capacity savings and recognize that it would clearly provide for all of the other value attributes that Mr. Beach identifies, the remaining portion of his total benefits range from 22.4 to 26.3 cents/kWh.

Additionally, for purposes of this comparison, I have chosen to exclude energy losses. Any losses actually avoided are small in magnitude. And I believe that a more detailed analysis would find that the incremental generation capacity and energy value benefits of grid-scale solar (versus rooftop solar) will more than offset the energy losses benefit of rooftop solar. What is also becoming more apparent is that some level of rooftop solar energy losses will be experienced, as the exported energy must utilize portions of the APS distribution system to reach other points of consumption. As rooftop solar penetration grows, some of our distribution feeders are actually experiencing an overall net export during certain times of the year.

Through publicly available PPA pricing information, we have a clear picture of what it would cost to obtain these identified benefits from a grid-scale solar PV system. A neighboring utility, NV Energy, recently signed a 20-year PPA with SunPower for a grid-scale solar PV plant near Boulder, Nevada. This facility is expected to be in operation prior to year end 2016. Most importantly, the levelized price of this PPA is 4.6 cents/kWh.[1] There is further evidence that this price is expected to continue to fall in the future as the City of Palo Alto signed a PPA for a grid-scale solar PV plant to be in service by 2021 at a levelized price of 3.6 cents/kWh.[2]

These PPA prices make clear that Mr. Beach's claimed 22.4 to 26.3 cents/kWh of benefits are grossly overstated and that the value of solar can, in fact, be obtained for a fraction of the price that Mr. Beach identifies in his analysis. Although Ms. Kobor focuses on methodology instead of calculating numbers, her analysis is likely to suffer from the same error. Based on the general similarities between Ms. Kobor's and Mr. Beach's methodologies, I think it is reasonable to assume that the consequences of her failure to analyze grid-scale solar would be similar to Mr. Beach's failure.

Q. DOES MR. BEACH EXPLAIN WHY CUSTOMERS SHOULD PAY 17.9 CENTS PER KWH FOR THE VALUE OF SOLAR WHEN THEY COULD PAY 4.6 CENTS, OR LESS?

A. I am not able to discern a justification for this methodological flaw in Mr. Beach's testimony, or in the filed testimony of any other party. This failure to consider grid-scale solar as a resource alternative gives rise to two primary questions: "How can the value

[1] *See* Application of Nevada Power Co. d/b/a NV Energy for Approval of the First Amendment to Its 2014 Emissions Reduction & Capacity Replacement Plan As It Relates to Two New Renewable Energy Purchased Power Agreements, Docket No. 15-07003 (Nev. Pub. Util. Comm'n Sept. 9, 2015).

[2] *See* Staff Report from City of Palo Alto Finance Committee on Wilsona Solar Renewable Power Purchase Agreement (Feb. 16, 2016), http://www.cityofpaloalto.org/civicax/filebank/documents/50920 (approved on Mar. 21, 2016, http://www.cityofpaloalto.org/civicax/filebank/documents/51640).

of the exported rooftop solar energy possibly be 22.4 to 26.3 cents/kWh when this same value can be obtained for 4.6 cents/kWh or less?" And, "Why should APS customers pay any more for this energy than what the best alternative would be for producing this energy?"

Other factors further underscore the magnitude of the difference between grid-scale and rooftop solar in obtaining the value of solar. This comparison between the two solar applications was kept at a high level to illustrate the point. A more detailed analysis would need to recognize the higher capacity, energy and curtailability values of grid-scale PV (all of which I described in my direct testimony). Furthermore, the cost of grid-scale solar PV (the 4.6 cents/kWh or lower identified above) should only be viewed as a "cap" on the value. It is possible that APS's current and future fleet of generating assets (both conventional and renewable) may be able to produce this energy at an even lower cost than the cited PPAs.

The importance of using grid-scale solar as a reference point becomes clear using Mr. Beach's own charts. In his Exhibit 2, Mr. Beach performs four different cost/benefit tests. The results of Mr. Beach's four cost/benefit tests for residential rooftop solar applications are summarized in his Figure 1 and Table 1. When one corrects the flaw in Mr. Beach's methodology by including grid-scale solar prices, the conclusions from these cost/benefit tests reverse. Instead of being cost-effective, residential rooftop solar no longer passes these cost/benefit tests (with the exception of the participant test which only looks at cost/benefit from the perspective of the participating rooftop solar customer). Mr. Beach's failure to consider grid-scale solar as an alternative means to acquire the value of solar is a profound methodological flaw that raises serious questions about whether his study is reliable or his conclusions are valid.

Q. DOES MR. BEACH GIVE ANY RATIONALE AS TO WHY GRID-SCALE IS NOT AN APPROPRIATE ALTERNATIVE ON WHICH TO BASE THE VALUE OF ROOFTOP SOLAR?

A. Yes. On page 29 of his testimony, Mr. Beach contends that grid-scale and rooftop solar are not comparable because grid-scale solar is a wholesale product, while rooftop solar is a retail product. Mr. Beach also contends that energy exported from rooftop solar should be considered a retail product because it displaces retail power provided by the utility.

Q. DO YOU AGREE WITH MR. BEACH'S ASSERTION THAT EXPORTED ENERGY SHOULD BE CONSIDERED A RETAIL PRODUCT?

A. No, I do not. Exported energy is thc quintessential wholesale product. It is sold to the utility, which in turn sells it to customers. Exported energy only displaces retail power in the same way that any power purchased from a third party supplier does—instead of delivering one electron to complete the retail transaction, the utility uses a different electron.

Displacing one source of electrons with purchases from another source does not change the nature of the underlying transaction. The electrons exported from rooftop solar look exactly the same to the non-solar customer as the electrons from the grid-scale solar or any other wholesale power source. Both are first sold to the utility at wholesale before the utility sells them in a subsequent retail transaction. Additionally, it is exactly those wholesale power sources (either grid-scale solar, conventional generating units or purchases from wholesale power suppliers) that would be used to replace the energy exported from the rooftop solar systems.

Q. DOES MR. BEACH GIVE ANY TECHNICAL REASONS WHY GRID-SCALE AND ROOFTOP SOLAR ARE NOT COMPARABLE?

A. No, aside from policy issues addressed below, Mr. Beach appears to concede that grid-scale solar can be adjusted so that it is comparable to rooftop solar from a technical and operational perspective. On page iv of his direct testimony, Mr. Beach states, "Thus, for a fair comparison between the two resources, at a minimum one must add to the cost of utility-scale solar the marginal costs associated with delivering this power to the customers that can be served by solar DG located on their own roofs. Furthermore, these resources differ in their value for Renewable Energy Standard compliance, and rooftop solar provides additional societal benefits to the local environment and economy."

Later in his testimony, however, Mr. Beach notes that rooftop solar would not bring RES compliance value to APS.[3] Setting aside for now the policy question of whether local environmental or economic benefits should be factored into rates, Mr. Beach statement suggests that grid-scale solar, adjusted for operational differences associated with energy losses and transmission and distribution infrastructure, would be equivalent to rooftop solar in terms of direct benefits. He does not, however, quantify such a comparison.

Q. WHAT POLICY REASONS DOES MR. BEACH GIVE TO PREFER ROOFTOP SOLAR OVER GRID-SCALE SOLAR?

A. On pages 30 and 31 of his direct testimony, Mr. Beach offers policy reasons why rooftop solar is preferable to grid-scale solar. These include claims that rooftop solar has a greater economic benefit than grid-scale solar, the resiliency of local power

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[3] *See* R. THOMAS BEACH, THE BENEFITS AND COSTS OF SOLAR DISTRIBUTED GENERATION FOR ARIZONA PUBLIC SERVICE 2016 UPDATE, page 8 (2016). Moreover, because APS does not purchase RECs from new rooftop solar customers, new rooftop solar installations do not contribute to APS's RES compliance requirements.

production, and alleged habitat impacts of grid-scale solar installations. APS witness Ashley Brown rebuts each of these policy claims in his direct and rebuttal testimony. In any event, Mr. Beach offers no explanation why these policy assertions justify customers paying 17.9 cents/kWh for the value of solar when they could pay 4.6 cents/kWh, or less.

Mr. Beach also argues that important policy considerations support pro-rooftop solar regulatory environments, including attracting new capital, new competition, grid services, enhanced reliability and resiliency, high-tech synergies, customer engagement, and self-reliance. None of these change the fact that grid-scale solar can acquire all the same value provided by rooftop solar that forms the basis of Mr. Beach's quantitative analysis.

In addition, Mr. Brown makes clear that the very policies Mr. Beach references actually harm the future of solar, and stifle alternative forms of distributed technologies. Contrary to Mr. Beach's assertion, the long-term future of rooftop solar and the policy considerations he identifies are better served by modernized rate design that causes distributed technologies to compete on the basis of cost rather than on their ability to arbitrage rate subsidies as discussed by Mr. Brown.

IV. <u>SEPARATE TREATMENT OF ROOFTOP SOLAR SELF-CONSUMPTION AND EXPORTS</u>

Q. BEYOND IGNORING THE COST-EFFECTIVENESS OF GRID-SCALE SOLAR, WHAT OTHER MAJOR FLAW UNDERMINES MR. BEACH'S VOS METHODOLOGY?

A. Mr. Beach treats all rooftop solar production—both energy that is consumed immediately by the customer and energy that is exported to the grid—as the same in developing a value of exported solar energy. This is not, however, an appropriate way to develop a value for exported energy. To assess the value of exported energy itself, the only appropriate course is to focus exclusively on the value and benefits attributable to exported energy only, not those provided by the self-consumed energy.

Q. MANY OF THE WITNESSES IN THIS PROCEEDING ASSERT THAT ROOFTOP SOLAR CUSTOMER SELF-CONSUMPTION AND EXPORTS SHOULD BE CONSIDERED SEPARATELY. DO YOU AGREE?

A. Yes, I do. And in fact, almost all of the parties to this case contend that this proceeding is about valuing only the exported rooftop solar energy. Specifically, Staff witness Howard Solganick, Ms. Kobor, and Vote Solar's second witness, Mr. Volkmann, as well as Mr. Beach all concur that the VOS methodology should establish the right value for exported energy. This is a logical distinction. Power supplied by the utility to the consumer is a retail product and should be priced at retail rates that are determined through a Cost of Service Study (COSS).

By contrast, power supplied by the customer to the utility is a wholesale product and should be priced at wholesale rates determined in the VOS process. What is critical, however, is to appropriately account for the very real differences between the two categories of rooftop solar energy. To establish a value for exported energy, one must look at the benefits of exported energy only, not at the total rooftop solar output.

Q. DO THE SELF-USE AND EXPORT PORTIONS OF THE ROOFTOP SOLAR OUTPUT HAVE DIFFERENT VALUES?

A. Absolutely. The value of energy to the utility varies by hour and the capacity value of a generating resource depends upon its output during the hours of peak customer demand. It is logical that rooftop solar customers will self-consume more of their solar output at times when it is more valuable. On hot summer afternoons at 5 p.m., energy is more valuable precisely because consumption is high and demand is greater relative to supply. It is also clear that customers will export more energy at times when it is less valuable, i.e. the non-summer midday, when consumption, and therefore demand, is lower. To value export energy the same as one values self-consumption grossly overstates the value of the exported rooftop solar energy.

Further, exported energy adds another layer of intermittency. Solar is already an intermittent resource due to weather-related conditions such as cloud cover. Assessing the capacity benefits of exported energy requires accounting for another factor—customer usage. Since the self-use always comes first (i.e., the export only occurs after first satisfying the customer's total load requirements), passing cloud events and/or increases in customer usage impact the exported energy first. It is difficult, if not impossible, to establish any capacity value after considering this double layer of intermittency.

Q. CAN YOU QUANTIFY THE DIFFERENCE BETWEEN SELF-CONSUMED AND EXPORTED ENERGY?

A. Using actual meter data on the peak load day of 2015 (August 15), APS observed that at the time of peak customer consumption (5 p.m.), only 5% of rooftop solar energy was being exported (as a percent of nameplate rating). And if one looks at the amount of rooftop solar energy exported during the top 90 hours,[4] the percentage only rises to 7%. Yet Mr. Beach attributes a capacity value of 36.2% to 53.2% to this exported energy (*see* Mr. Beach's Table 5).

[4] APS uses a top 90 hours analysis as a proxy for a full-blown Effective Load Carrying Capability (ELCC) analysis to estimate capacity value.

Q. WHAT IS THE EFFECT ON MR. BEACH'S ANALYSIS IF THE CAPACITY VALUE IS CORRECTED TO REFLECT THAT ONLY 5% TO 7% OF ROOFTOP SOLAR ENERGY IS EXPORTED AT THE PEAK PERIOD?

A. The effect is dramatic, and is critical to accurately perform any VOS analysis. If I were to accept the rest of Mr. Beach's methodology in Tables 4, 5 and 6, and only account for the fact that 5% rooftop solar energy was being exported at the time of peak customer consumption in 2015, Mr. Beach's claimed savings for generation, transmission, and distribution capacity from exported energy would drop from 10.6 cents/kWh to 1.2 cents/kWh. Looking at the top 90 hours, these capacity values drop from 10.6 cents/kWh to 1.7 cents/kWh.

Q. HAS APS COLLECTED AND ANALYZED DETAILED CUSTOMER DATA IN ORDER TO UNDERSTAND THE TRUE NATURE OF SELF-USE AND SOLAR EXPORTS?

A. Yes, we have analyzed the available data for 28,826 residential customers who had rooftop solar systems that were operating for all of 2015. We excluded customers for whom we did not have complete information and customers that installed rooftop solar after January 1. At the end of 2015, we had 39,171 rooftop solar residential customers on our system, so the analysis covers a large portion of our current rooftop solar customer base, and can be used to accurately understand and characterize solar self-consumption and exports in our service territory. It is significant that this represents real system conditions based on actual metered data; it is not modeled or projected or subject to assumptions.

Q. PLEASE SUMMARIZE YOUR ANALYSIS.

A. Figure 2 presents a high level summary of the analysis. The nameplate capacity of the studied systems was 200 MW_{DC}, or 170 MW_{AC}.[5] During 2015, our sample rooftop solar customers generated 339,356 MWhs from their rooftop solar units. Of that, 156,136 MWhs (or 46%) were self-consumed and 183,220 MWhs (or 54%) were exported to the grid for use by our non-solar customers. At APS's peak load hour, 5 p.m. on August 15, 2015, these rooftop solar units were producing 72.8 MWs and these customers were self-consuming 64.0 MWs, therefore exporting 8.8 MWs to the grid. And over APS's 90 highest net system load hours for the entire year (net of grid-scale renewable energy contribution), rooftop solar customers exported an average of 11.5 MWs to the grid. The maximum export during any one hour was 128.6 MWs which occurred on April 16 at 1 p.m.

One of the most interesting aspects of this data is that it indicates these rooftop solar customers actually export more energy over the course of the entire year than they use to offset their own consumption. This is in contrast to the statement that Mr. Beach makes on page 13 of his direct testimony that only 30 – 40% of the total rooftop solar output is exported. The actual data indicates that these rooftop solar systems look more like a wholesale generator than an "energy efficiency" device.

[5] Rooftop solar produces direct current, or DC power. Alternating current (or AC) power is what flows on the grid. Before rooftop solar energy is exported to the grid, it is converted to AC power. Unless otherwise noted, all capacity measurements in this testimony are stated in AC.

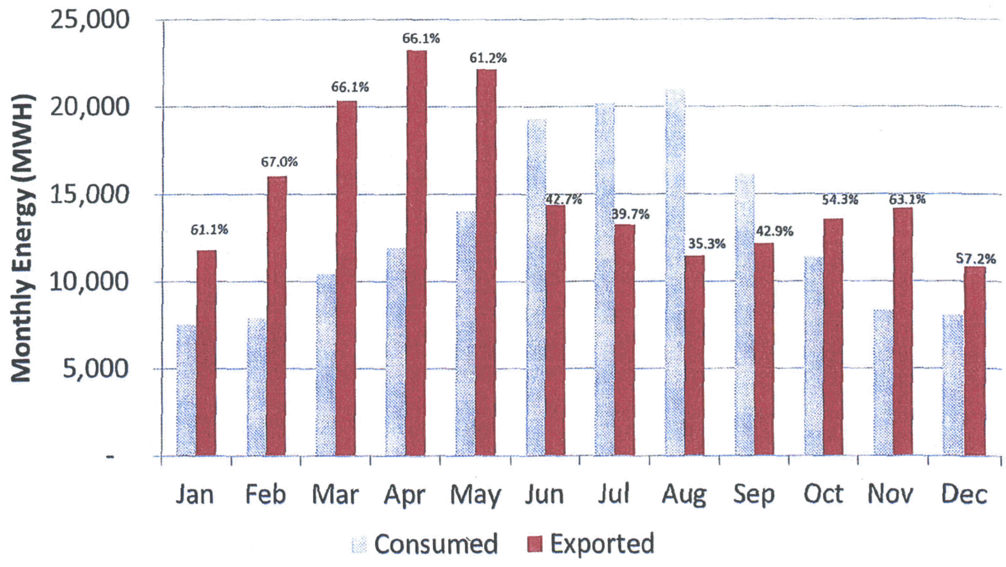
Figure 2 – Summary of Residential Solar DG Analysis

Residential Systems Included	28,826
Nameplate Rooftop Solar Capacity (MWs-AC)	170
Total Rooftop Solar Production at Peak Load Hour (MWs)	72.8
Self-Consumption at Peak Load Hour (MWs)	64.0
Total Exported at Peak Load Hour (MWs)	8.8
Maximum Export on April 16, 2015 at 1 p.m. (MWs)	128.6
Average Exported Over Top 90 Hours (MWs)	11.5

Q. PLEASE PROVIDE MORE INFORMATION ABOUT THE SEASONAL NATURE OF ROOFTOP SOLAR GENERATION.

A. Over the course of the year, exported rooftop solar energy was highest in April and May, with rooftop solar customers exporting about two-thirds of the total energy produced during these months. During the summer period of June through September, total solar generation was still high, but rooftop solar customers self-consumed about 60% and exported 40% to the grid. The primary difference between the summer and non-summer periods is the degree of customer usage. During the summer, customers consume more with air conditioning units running. In the non-summer period, they consume less and more rooftop solar energy is available to be exported to the grid. Figure 3 provides the amount of self-consumption and export energy on a monthly basis, as well as the percentage that is exported on a monthly basis.

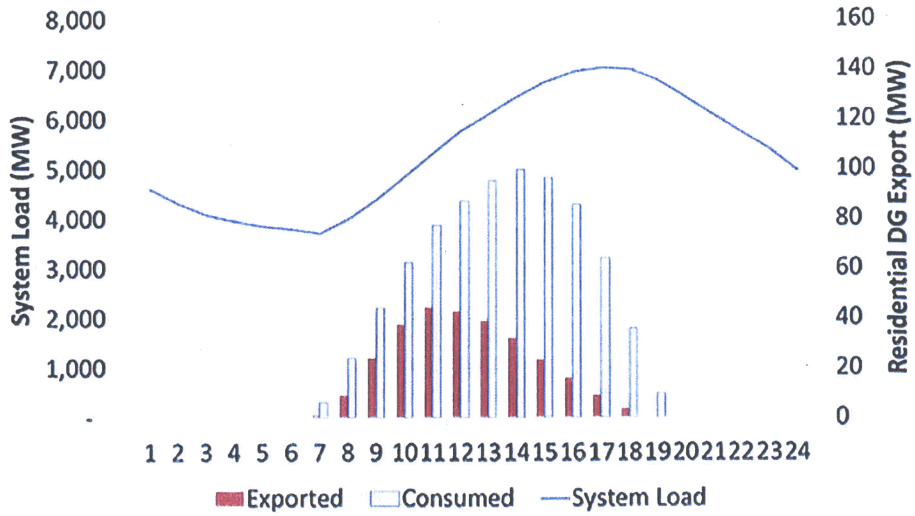
Figure 3 - Residential Rooftop Solar Self-Consumption and Export



Q. ON APS'S PEAK DAY IN 2015, HOW DID ROOFTOP SOLAR GENERATION, BOTH SELF-CONSUMED AND EXPORTED, COMPARE TO APS'S LOAD SHAPE OVER THE COURSE OF THE DAY?

A. Figure 4 sets forth the relevant data. During all hours of rooftop solar production, our rooftop solar customers self-consumed more energy than they exported to the grid. The maximum export occurred in the morning when APS system load was relatively low, and steadily declined after 11 a.m. for the rest of the day as customer consumption continued to build. During the late afternoon hours, when APS customer consumption was peaking, rooftop solar customers self-consumed the vast majority of their rooftop solar generation and exported very little. And, when APS hit its annual peak load at 5 p.m., rooftop solar was exporting only 8.8 MWs to the grid, or about 5% of the aggregate nameplate capacity of all residential rooftop solar systems. Over the course of the day, rooftop solar customers self-consumed 74% of their solar output, and only exported 26% to the grid.

Figure 4 – Residential Rooftop Solar on August 15, 2015



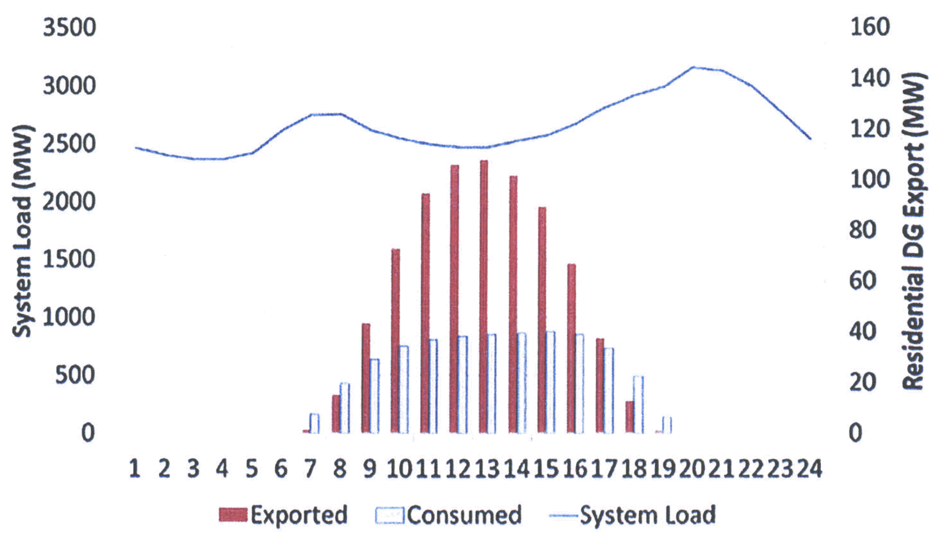
Q. WHAT CONCLUSION DO YOU DRAW FROM THE FACT THAT ROOFTOP SOLAR ONLY EXPORTED 8.8 MWS AT APS'S PEAK?

A. This data makes it clear that the vast majority of capacity-related benefits from rooftop solar are captured by rooftop solar customers themselves. There is very little generation, transmission, or distribution capacity related benefits left to be allocated to the export portion of the rooftop solar energy production.

Q. PLEASE EXPAND ON YOUR DISCUSSION OF HOW ROOFTOP SOLAR GENERATION WAS SELF-CONSUMED AND EXPORTED DURING A SHOULDER MONTH DAY.

A. During non-summer (or shoulder) periods, APS's system load is much lower than it is in the summer. During most solar hours of the day, rooftop solar customers export much more than they self-consume. The month of April provides a good example of what happens during a shoulder month. Figure 5 shows that on a typical day in April 2015, our rooftop solar customers' self-consumption pattern was fairly steady from about 9 a.m. to 5 p.m., and their exports were the highest at midday while system loads were dipping.

Figure 5 – Residential Rooftop Solar on a Typical April Day (2015)



Q. WHAT DO YOU CONCLUDE FROM THE RELATIVELY LARGE AMOUNT OF ROOFTOP SOLAR ENERGY EXPORTED DURING LOW LOAD PERIODS?

A. I conclude that there is a significant mismatch between when rooftop solar customers export to the grid and when the energy is most valuable. Due to low demand during shoulder periods, the relatively high supply of exported rooftop solar energy is simply not very valuable.

Q. IS IT APPROPRIATE TO USE THE SHAPE OF THE TOTAL SOLAR OUTPUT OF A RESIDENTIAL ROOFTOP SOLAR SYSTEM TO DEVELOP THE VALUE OF THE EXPORT?

A. No, it is entirely inappropriate to take a value derived from the total rooftop solar output and apply it to exported energy. The value of exported energy must be based on the specific timing of when it is delivered to the grid.

Q. IN FIGURE 1 OF MR. BEACH'S TESTIMONY, HE SHOWS THAT RESIDENTIAL ROOFTOP SOLAR PASSES ALL FOUR COST-BENEFIT TESTS AND CONCLUDES THAT IT IS A COST EFFECTIVE RESOURCE. DO YOU AGREE WITH HIS CONCLUSION?

A. Absolutely not. If Mr. Beach had correctly accounted for the limited value of exported energy, residential rooftop solar would have failed three of the four tests, and the conclusion would have been that it is not a cost effective resource for anyone other than the rooftop solar customer. The only cost test that would still show a favorable result is the participant test, which only looks at the cost/benefit from the perspective of the participating rooftop solar customer.

In Figure 6 below I show what Mr. Beach should have concluded if he had applied his methodology correctly. It captures all of the separate value components that Mr. Beach claims are provided by solar, and adjusts the total to reflect a capacity value that is based on exported rooftop solar energy only. Note that Figure 6 only accounts for two of the flaws that I have identified in Mr. Beach's methodology.

Figure 6 – Summary of Corrections Made to Mr. Beach's Table 11

(all numbers are in cents/kWh)

Value Category	Residential Values (avg. of south + west)	Comments	Adjusted Value
Energy	6.2	Provided by grid-scale solar (energy losses not included, see note below)	-
Fuel Price Hedging	0.9	Provided by grid-scale solar	-
Market Price Mitigation	1.0	Provided by grid-scale solar	-
Capacity	7.0	Provided by grid-scale solar	-
Transmission	1.3	Corrected for lower export capacity contribution during peak hours	0.2
Distribution	2.3	Corrected for lower export capacity contribution during peak hours	0.6
Carbon	3.3	Provided by grid-scale solar	-
Criteria Pollutants	1.1	Provided by grid-scale solar	-
Water	0.2	Provided by grid-scale solar	-
Local Economic Benefits	4.7	Provided by grid-scale solar	-
Total	**28.0**		
Grid-scale solar (unadjusted)		Not adjusted for higher capacity value, energy value or curtailability benefits. The value is the average of the two grid-scale PPA prices cited earlier in this rebuttal testimony.	4.1
Adjusted Total			**4.9**

- Note that energy losses were excluded from this analysis. I believe that the higher generation capacity, energy and curtailability values of grid-scale solar would more than offset the energy loss benefits of rooftop solar.

Q. IS 4.9 CENTS PER KWH THE VALUE OF SOLAR ACCORDING TO APS?

A. No. This calculation only shows a corrected version of Mr. Beach's analysis. It is clear that a grid-scale solar system provides a higher value product than exported rooftop solar energy in terms of both energy value and generation capacity value. The base grid-scale solar value is consistent with a published grid-scale solar PPA rate for the higher-value grid-scale product. To ensure an accurate comparison with the lower-value rooftop solar product, the PPA rate would need to be adjusted downward to reflect the lower energy and capacity values provided by rooftop solar. I discuss these adjustments in greater detail in my direct testimony. For this simple comparison, however, I have not performed the calculations necessary to show the impact on the overall value from these and other variables.

V. SPECIFIC CONCERNS REGARDING MR. BEACH'S REPORT

Q. ASIDE FROM CONFLATING SELF-CONSUMED AND EXPORTED ENERGY, AND THE FAILURE TO CONSIDER GRID-SCALE SOLAR, DO YOU HAVE OTHER CONCERNS WITH MR. BEACH'S ANALYSIS?

A. Yes, as a general matter, the analysis is based on numerous predictions about what might happen in the future, including both load growth and customer behavior. Mr. Beach relies on projections APS made regarding future capacity needs in connection with APS's 2014 Integrated Resource Plan. This was appropriate for purposes of assessing future resource needs at that time. As time passes, APS updates its resource plans with and makes procurement decisions based on the best available information. But only actual costs are used to set rates; rates are not set on the future projections of resource values.

Moreover, Mr. Beach includes societal values without acknowledging that societal values are not included in rates and cannot be accurately quantified. Finally, Mr. Beach relies on numerous flawed assumptions designed to produce an over-the-top estimate of the value of solar. Mr. Beach's value of solar methodology appears to exemplify many of the flaws associated with attempting to set rates based on a long-term resource valuation. I provide examples below.

Q. WHAT FLAWS EXIST WITHIN MR. BEACH'S ENERGY SAVINGS METHODOLOGY?

A. Mr. Beach's assessment of energy value contains several flaws:

- Mr. Beach readily acknowledges that his natural gas prices are out of date. Although Mr. Beach claims that correcting utility rate escalation can address this problem, this is not true. Natural gas only contributes a portion of the energy costs in APS's retail rates. The relationship between natural gas prices and retail rates is not one to one, and reducing Mr. Beach's retail rate escalation cannot correct for his use of inaccurate natural gas prices.

- Mr. Beach fails to account for the possibility of negative pricing. As discussed in my direct testimony, negative pricing involves APS receiving compensation for taking excess power from neighboring utilities. It is inaccurate to assume, as Mr. Beach does, that rooftop solar will permit ever-increasing energy savings over time when, in fact, rooftop solar energy might hinder APS's ability to take advantage of negative prices and, hence, the value of the rooftop solar export energy could be negative during some hours in the future.

- Mr. Beach's energy savings analysis includes non-existent carbon tax costs. Including potential future carbon costs is the appropriate, conservative approach when planning resources. But it is inappropriate to include non-existent costs when setting rates.

Q. WHAT ARE THE FLAWS IN MR. BEACH'S CLAIMS REGARDING TRANSMISSION CAPACITY SAVINGS?

A. Mr. Beach generically estimates transmission capacity savings based on generation capacity savings. This methodology suffers from the flaw relating to exported energy discussed above. In addition, it is a generic assessment. APS's recently filed Biennial

Transmission Assessment provided a detailed study of actual transmission projects that might be deferred or avoided by rooftop solar and found a single potential project that could be deferred and that most of that result was due to the impact of energy efficiency programs, not rooftop solar.[6] Compared to Mr. Beach's generic analysis, APS's specific study offers a more accurate conclusion regarding actual projected transmission capacity savings.

Q. IS MR. BEACH'S METHOD FOR CALCULATING DISTRIBUTION SAVINGS FLAWED?

A. Yes. Mr. Beach's method for calculating distribution savings assumes that on-peak capacity related savings occur, and that for every MW of peak load reduction, a MW of distribution can be deferred. Unless APS can actually reduce distribution expenditures due to rooftop solar, these savings will never occur.

Given that we have a large distribution system already in place, and that we are unlikely to reduce new construction on the chance that future customers might install solar, the opportunity for distribution savings is very limited. APS has undertaken a detailed evaluation of its distribution system and has found almost no opportunity for significant distribution savings, as was documented in the R.W. Beck and SAIC studies previously discussed in this docket.

If distribution savings are valued at all, they need to be based on detailed analysis of the distribution system that will produce verified savings, and not Mr. Beach's system average approach in which the purported savings will never materialize. This kind of

[6] ARIZ. PUB. SERV. CO., TECHNICAL STUDY ON THE EFFECTS OF DISTRIBUTED GENERATION AND ENERGY EFFICIENCY ON FUTURE TRANSMISSION NEEDS, Docket No. E-00000D-15-0001 (Jan. 29, 2016).

analysis is particularly needed if the focus is on exported energy that has even less contribution at the time of system peak.

Q. MR. BEACH CONTENDS THAT ROOFTOP SOLAR SHOULD BE VALUED USING INCREMENTAL RATHER THAN SYSTEM AVERAGE LOSSES. DO YOU AGREE?

A. No. In my direct testimony I explain why we should not use incremental losses. And considering that self-consumption occurs during higher load times, and exports are delivered at lower load times when losses are lower, it makes even less sense to use incremental losses. If I were to use our average system energy loss rate of 7% versus the incremental loss rate of 12% used by Mr. Beach, this would reduce his calculated energy value by 0.3 cents/kWh.

Q. MR. BEACH APPLIES A 15% RESERVE MARGIN MULTIPLIER TO THE CAPACITY VALUE. IS THAT CORRECT?

A. No. That is already accounted for in the way APS develops ELCC capacity value, so applying it in the way that Mr. Beach does in his analysis amounts to double-counting this value. Eliminating this value from Mr. Beach's calculation reduces his generation capacity value by 1 cent/kWh.

Q. MR. BEACH ASCRIBED NEARLY ONE CENT PER KWH OF FUEL HEDGING VALUE TO ROOFTOP SOLAR GENERATION. IS THAT APPROPRIATE?

A. Absolutely not. It appears that Mr. Beach might have misunderstood or misinterpreted information acquired from APS to develop this value. The data request response that Mr. Beach relies upon, included as Attachment BJA-1RB to this testimony, shows an approximate annual average of $50 million as the difference between APS's hedged cost of natural gas and the price of natural gas on the spot market for the years 2003 through 2012. However, this is not the same as APS's costs to hedge natural gas.

Instead, it costs APS fractions of a cent per MMBtu to hedge natural gas prices. It is this cost to hedge natural gas that could be the only relevant value in a value of solar analysis. To the extent rooftop solar would assist APS in hedging natural gas prices (which Mr. Beach asserts, but does not prove), APS would only avoid its hedging costs, not the difference between the hedged cost of natural gas and the price of natural gas on the spot market. Hedge value should not be included in the value of rooftop solar calculation in the first place, but even if it was, it would truly be negligible.

Q. MR. BEACH ALSO ASCRIBED ONE CENT PER KWH VALUE OF MARKET PRICE MITIGATION VALUE TO ROOFTOP SOLAR. IS THAT APPROPRIATE?

A. Absolutely not. Mr. Beach claims regarding market price mitigation rely on highly theoretical numbers from a 2010 study that cannot be considered in this VOS docket. The 2010 study is based on outdated market information and prices. Significant changes to the wholesale power market, including fundamental shifts in natural gas supply caused by hydraulic fracturing technology, make any study in 2010 essentially useless for accurately assessing future market trends.

Perhaps more importantly, the study upon which Mr. Beach relies considers all solar, not just rooftop solar, much less exported energy. And the study highlights additional costs caused by solar penetration, including the need for gas turbine "peaking units" and the potential need for "expensive generation to be brought on line" to make up for forecast errors.[7] APS did not separately investigate details related to the additional costs referenced in the NREL study. What is notable, however, is that Mr. Beach appears to ignore the warning in this study upon which he relies regarding potential costs

[7] *See* NREL AND GE CONSULTING, IMPACT OF HIGH SOLAR PENETRATION IN THE WESTERN INTERCONNECTION, PAGE 7-8 (2010), http://www.nrel.gov/docs/fy11osti/49667.pdf.

associated with solar, and instead only references those aspects of the study that support his position. Finally, assuming market price mitigation actually does occur, even Mr. Beach acknowledges that the largest reductions have already occurred.

Q. TASC WITNESS BEACH AND VOTE SOLAR WITNESS KOBOR ASSERT THAT ENVIRONMENTAL BENEFITS OF ROOFTOP SOLAR EXPORTS SHOULD BE INCLUDED IN THE VOS ANALYSIS. MS. KOBOR GOES ON TO SAY THAT THE ACC REQUIRES UTILITIES TO USE THE SOCIETAL COST TEST IN EVALUATION OF DSM PROGRAMS AND THAT THE RULES SPECIFICALLY ADDRESS THE INCLUSION OF ENVIRONMENTAL IMPACTS. DOES THE COMMISSION REQUIRE YOU TO MONETIZE ENVIRONMENTAL IMPACTS?

A. No. Ms. Kobor is correct that APS is required to perform a DSM cost-effectiveness test using Staff's Societal Cost Test methodology.[8] That methodology quantifies environmental impacts (i.e., reduced tons of NOx, Sox, CO2, and particulates), but does not assign a monetary cost to them. Likewise, both TASC's and Vote Solar's methodology would have us give monetary credit for purported fuel or market price mitigation, hedging expenses, distribution savings, and other externalities savings, but those are not included in Staff's Societal Cost Test either.

Q. DO VOTE SOLAR AND TASC ADVOCATE ANY OTHER ITEMS FOR CALCUATING THE VALUE OF SOLAR THAT WOULD BE IN CONFLICT WITH THE WAY DSM TESTS ARE DONE IN THIS JURISDICTION?

A. Yes, there are at least two. Ms. Kobor advocates using a marginal loss rate and a societal discount rate (approximately equal to the inflation rate). Our Societal Cost Test in practice uses an average loss rate and after tax weighted cost of capital as the discount rate. Further, DSM tests in Arizona quantify societal costs, but do not monetize them.

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[8] *In re* Appl. of Ariz. Pub. Serv. Co. for Approval of the Company's 2012 Demand Side Mgmt. Implementation Plan, Decision No. 73089 (Ariz. Corp. Comm'n Apr. 5, 2012).

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

APS 5

Before the
Public Service Commission of Utah

In The Matter of the Investigation of the) Costs and Benefits of PacifiCorp's Net) Metering Program)	Docket No. 14-035-114

Sur-Rebuttal Testimony of
Tim Woolf

On The Topic of
The Benefit-Cost Framework for Net Energy Metering

On Behalf of
Utah Clean Energy, the Alliance for Solar Choice, and Sierra Club

September 29, 2015

EXHIBIT
APS-7
ADMITTED

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. I am providing evidence on behalf of Utah Clean Energy, the Alliance for Solar Choice, (TASC) and Sierra Club (together the "Joint Parties").

Q. What is the purpose of your sur-rebuttal testimony?

A. The purpose of my sur-rebuttal testimony is to respond to the rebuttal testimonies presented by Rocky Mountain Power (RMP), the Office of Consumer Services (OCS), and the Division of Public Utilities (the Division), and to clarify apparent misunderstandings of the Joint Parties' proposal for an analytical framework for evaluating the costs and benefits of the net metering (NEM) program.

2. RECMMENDATION FOR A NEM BENEFIT-COST FRAMEWORK

Q. Please begin by summarizing your primary recommendation for how to evaluate the costs and benefits of NEM.

A. My recommendation is fairly simple. It has three elements to it:

- <u>Two different metrics</u> are necessary to understand the costs and benefits of NEM on all customers: a cost impact analysis (i.e. revenue requirements for RMP's system), and a rate impact analysis (i.e. non-NEM customer impact).

- To examine costs and benefits to the utility's system, a cost impact analysis should be conducted in terms of the net present value of revenue requirements (PVRR), which is the same framework that is used to evaluate the costs and benefits of all other types of electricity resources in Utah.
- To examine the costs and benefits to non-NEM customers, a rate impact analysis should build off of the methodologies and inputs to the cost impact analysis, and should indicate the short-term *and* long-term impacts on customer rates as a result of NEM.

The results of the cost impact analysis will indicate the net benefits (costs) of NEM to the utility system and all customers as a whole; in other words the extent to which NEM will reduce (or increase) revenue requirements. The result of the rate impact analysis will indicate the extent to which non-NEM customers will be affected by any cost-shifting that occurs as a result of NEM; in other words the extent to which NEM will increase (or reduce) customer rates. Taken together, these two analyses will provide an indication of the costs and benefits the Company's system will incur from NEM, and the costs and benefits that other non-NEM customers will incur from NEM. These results can then be used as inputs and considerations to a subsequent rate design process.

3. SUMMARY OF KEY REBUTTAL ARGUMENTS FROM OTHER PARTIES

Q. Are there any overarching points about the other parties' rebuttal that you would like to make?

A. Yes. The most striking part of the other parties' rebuttal testimonies is what is missing from them. None of the other parties provide a meaningful rebuttal to the two key elements of my proposal. In particular:

- Cost impact analysis. None of the other parties explain why the costs and benefits of NEM resources should be evaluated using a different methodology than that used for other resources and for integrated resource planning in Utah and elsewhere. The only arguments that are provided are based on the notion that such a methodology cannot be used for setting rates. However, as described below, setting rates is not the purpose of this docket. The Commission directed parties in this docket to develop the benefit-cost framework, which is what the Joint Parties have done.
- Rate impact analysis. None of the other parties explain why a sound, long-term rate impact analysis cannot or does not provide a useful indication of the extent to which costs might be shifted between NEM and non-NEM customers.

In the absence of meaningful rebuttal arguments to these two key recommendations of my proposal, the Commission should conclude that they are sound recommendations and should be used for the NEM cost-benefit framework.

Q. Please summarize some of the key arguments that other parties make to rebut your proposal.

A. Several of the other parties made similar arguments on three points, whichI would like to address up front. First, some parties argued that my proposal cannot be used to set rates. RMP argues that "The Utility Cost test is an important tool for determining the cost-effectiveness of resource acquisition. However it is not used to set rates."[1] Similarly, DPU argued that "Mr. Woolf's analysis can have no real application to the setting of rates."[2]

Second, some parties challenge the way that I have characterized lost revenues, and the impacts that lost revenues have on evaluating NEM costs and benefits. RMP contests my point that lost revenues are not a new, incremental cost, and notes that "NEM customers are currently compensated for their excess generation at full retail rates. This is an incremental cost that will ultimately be paid for by non-participating customers."[3] RMP also contests my point that lost revenues should not be included in the cost impact analysis because they represent existing costs that are recovered from NEM customers regardless of whether NEM exists.[4] OCS agrees with me that the RIM test (which includes lost revenues) should not be used to analyze NEM costs and benefits, but argues

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1 Steward Rebuttal Testimony, page 6, lines 120-121.
2 Davis Rebuttal Testimony, page 8, line 145.
3 Clements Rebuttal Testimony, page 19, lines 398-400.
4 Steward Rebuttal Testimony, page 8, lines 162-171.

that no party has proposed the RIM test in this proceeding and therefore it does not warrant further discussion.[5]

Third, some parties argued with the comment in my direct testimony that "PV generation is essentially a free resource to the utility system, and it is provided at a time when power costs are typically at their highest." RMP argued that PV generation is not free, and that it does not necessarily occur at peak hours.[6] DPU also argued that PV generation does not necessarily occur at peak hours.[7]

I address these points in the following sections.

4. BENEFIT-COST ANALYSES AND RATE DESIGN

Q. Do you agree with the rebuttal critique that your proposal cannot be used for setting rates or rate design?

A. No, although it is important to be clear that the cost-benefit framework, in and of itself, should not be used for setting rates or for rate design anyway. Cost-benefit analyses are never used for setting rates or for rate design. Cost-benefit analyses are used for the purpose of determining which resources the utility should acquire. Once the resource acquisition determination has been made, then rates can be designed in such a way as to address cost causation and customer equity issues. The Commission has been clear that the benefit-cost analysis should be a separate exercise from the rate-setting and rate

5 Beck Rebuttal Testimony, pages 3-4, lines 56-72.
6 Clements Rebuttal Testimony, pages 17-8, lines 362-394.
7 Davis Rebuttal Testimony, page 9, lines 164-176.

design process. These rebuttal points are further evidence that the other parties have conflated the purposes and the practices of cost-benefit analyses and rate design.

Furthermore, it is important to be clear that the results of the benefit-cost analysis should be used as inputs for rate design. In other words, the rate design considerations should be made *in light of* the benefit-cost analysis. In this way, my NEM cost-benefit framework proposal can most certainly be used in setting rates and in rate design. However, it is used as an input to the rate design decisions; the rate design decisions are not used as an input to the cost-benefit analysis.

5. LOST REVENUES AND COST SHIFTING

Q. Do you agree with the rebuttal arguments that lost revenues should be included in the cost-benefit analysis?

A. No, not at all. It is very important to be clear about the role of lost revenues because they are central to the issue of cost-shifting. The Company states that NEM customers are "paid" for their generation at an amount equal to their retail rate. In fact, from the perspective of the utility, and the perspective of revenue requirements, there is no such "payment," i.e., no money flows directly from the Company (or other ratepayers) to the NEM customer as a result of the PV generation. Instead, what happens is that the NEM customer pays the Company less than it otherwise would have. In other words, the Company *recovers less revenues* than it otherwise would have. These are commonly referred to as lost revenues, and these occur with energy efficiency resources as well as customer-side PV.

Q. Why are lost revenues from customer-side PV such an important issue?

A. Lost revenues from customer-side PV are an important issue because they can ultimately lead to cost-shifting between NEM and non-NEM customers. This occurs because electricity rates include both variable ad fixed costs. Customer-side PV can avoid the variable system costs embedded in rates, but not the fixed costs (at least in the short-term). Therefore, lost revenues result in "lost contribution to fixed costs." If the utility does not recover the full contribution to fixed costs, then it may not collect enough revenues to cover its total costs. At the time of the next rate case, the utility will increase rates to reflect the reduced sales levels and to be sure to make up for any lost contribution to fixed costs going forward. This increase in rates will be experienced by all customers in the relevant rate class. It is this increase in rates that leads to a shifting of costs from NEM customers to non-NEM customers.

This process is why I recommend that, in addition to the cost-benefit analysis, the analytical framework also include a rate impact analysis. Before designing rates for net metering and non-net metering customers, the Commission must evaluate the cost-shifting issue by analyzing rate impacts. Once the Commission has gathered information on the costs and benefits incurred by other customers from the net metering program, then it can develop rates in light of those costs and benefits. Rate design is the appropriate mechanism to address any cost shifts; limiting the acquisition of a least-cost resource is not.

Q. Do the other parties include lost revenues in their NEM benefit-cost framework?

A. Yes. Both the RMP proposal and the OCS proposal, as described by Witness Hayet, clearly include lost revenues in the calculation of NEM costs.[8]

Q. Witness Beck claims that no party in this docket is proposing the RIM test, and therefore it does not warrant discussion. Do you agree?

A. No. The only difference between the Utility Cost test and the RIM test is that the RIM test includes lost revenues. In my view, any benefit-cost analysis that includes lost revenues is essentially the same as the RIM test. While some parties may not wish to call it the RIM test, there is no question that including lost revenues in the benefit-cost analysis is essentially equivalent to using the RIM test.

As noted above, other parties do include lost revenues in their proposed cost-benefit frameworks, so there is no question that lost revenues are relevant to this discussion. In fact, lost revenues are the primary contribution to the most vexing issue in this entire docket: how to address the impacts of cost-shifting.

Q. How do you recommend that lost revenues, and related cost-shifting, be addressed in the NEM benefit-cost framework?

A. Lost revenues should not be included in the cost impact analysis. As I describe in my direct testimony, lost revenues are not a new cost, do not affect revenue requirements,

[8] Clements Direct Testimony, pages 10-11, lines 230-237; Hayet Direct Testimony, page 9, lines 200-207.

and will not increase *revenue requirements* regardless of the NEM generation, and therefore, they should not be included in the cost-impact analysis.

However, lost revenues *should be* considered in the rate impact analysis. The very purpose of the rate impact analysis is to estimate the likely impact on customers as a result of any cost shifting from NEM, *which is caused by lost revenues from NEM.*

In my illustrative rate impact analysis, the lost revenues are included in the calculations. This is achieved by estimating future rates in the "With PV" case in such a way that the utility is allowed to recover its costs despite the reduced rates in that case. Figures 1 and 2 in my direct testimony indicate what the magnitude of the lost revenues are likely to be under the cases analyzed.

6. PV GENERATION IS A VERY LOW-COST RESOURCE

Q. Do you agree with the rebuttal to your statement that PV generation is essentially a free resource?

A. No, I do not agree with the rebuttal testimony on these points. First, I acknowledge that NEM may require some costs from the utility, in terms of administration costs and costs for supporting the distribution grid. For this reason, I include these costs in my cost impact analysis.[9] My point here is that the vast majority of the costs of the power, the equipment cost, the installation cost and any maintenance costs, are paid for by the host customer, not the utility and not the other customers. Therefore, this power is

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[9] Woolf Rebuttal Testimony, pages 34-35, lines 645-654.

"essentially" free. Maybe it would be more accurate to say that this power is "very low cost."

With regard to the timing of the PV generation relative to peak demands, I was just making a very general point. This point about the timing of PV generation does not in any way undermine the NEM cost-benefit framework that I have proposed. In general, the cost-benefit analysis should use the best information available to determine the avoided costs of PV for when it is likely to be generating.

7. OTHER REBUTTAL ARGUMENTS

Q. RMP argues that the DSM cost-benefit tests are not relevant for analyzing the costs and benefits of NEM. Do you agree?

A. No. I address the arguments made by the Company on this point in my rebuttal testimony.[10] In sum, there is no meaningful difference between DSM and NEM resources that would warrant fundamentally different treatment in evaluating cost-effectiveness. The Company argues that the DSM tests would have to be fundamentally altered in order to be used for NEM.[11] This is simply not true. The Utility Cost test can, and should, be used for the cost impact analysis; there is no need for any modifications to the structure of that test.

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[10] Woolf Rebuttal Testimony, pages 17-20, lines 312-383.
[11] Steward Rebuttal Testimony, pages 7-8, lines 155-161.

It is fair to say that the Utility Cost test would need to be *supplemented* by analysis of the cost-shifting, lost revenues, and rate impacts of NEM. But this does not require a new or a modified test, as this can be achieved with a rate impact analysis.[12]

Q. Some parties argue that the avoided costs used in your illustrative analysis are too high or too speculative.[13] Do you agree?

A. No. Again, this topic is not central to my testimony, and is addressed in the testimony of Witness Norris for the Joint Parties. In general, the cost-benefit analysis should use the best information available to determine the avoided costs of PV. This criticism of my testimony has no bearing on the validity of my central recommendations for an analytical framework for how to analyze the costs and benefits of NEM to the utility system, including non-NEM customers.

Q. OCS claims that you have mischaracterized the effect that NEM credits will have on the low-income discounted rates, and on revenue requirements.[14] Do you agree?

A. No. Witness Beck does not explain why she believes it is a mischaracterization. It is simply a fact that any NEM credits that remain at the end of a year will be used to help pay for the low-income discount rate, reducing the revenue otherwise required in the absence of the credits. Any such reduced revenue requirements would represent a benefit to all the customers that contribute to the low-income discount rate.

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[12] I have argued in several contexts that rate impact analyses should be applied to DSM, to supplement the results of the benefit-cost analysis, for the same reasons that they should be applied to NEM benefit-cost analyses.

[13] Clements Rebuttal Testimony, page 16, lines 347-358; Hayet Rebuttal Testimony, pages 13-14, lines 263-277.

[14] Beck Rebuttal Testimony, page 8, lines 173-176.

Q. DPU claims that your proposal would rely upon IRP information that is not necessarily relevant to NEM.[15] Do you agree?

A. No. Witness Davis refers to several elements of the Company's current IRP, and notes that some of them are not consistent with the addition of PV to the RMP system. While this may be true, these points do not suggest that my proposal is inappropriate. I am not suggesting that the Company's current IRP be used for this purpose, or necessarily any future IRP if it is not consistent with NEM development. My primary point is that the central underlying methodology of evaluating resources in an IRP, by using the present value of revenue requirements, should be used for the NEM cost-benefit analysis.[16]

8. CONCLUSIONS AND RECOMMENDATIONS

Q. Are any of the arguments made by other parties in their rebuttal testimonies meaningful, or compelling enough to suggest that your analytical framework is not appropriate or should be modified in any way?

A. No. None of the parties provided any compelling evidence as to why the costs and benefits of NEM should be treated any differently than other electricity resources. Instead, the criticism from other parties stems from the conflation of cost-effectiveness and rate design. None of the parties provided any evidence to suggest that long-term rate impact analyses cannot, or should not, be used to indicate the extent to which NEM might

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[15] Davis Rebuttal Testimony, page, 10 lines 184-193.

[16] Ideally, the IRP inputs and assumptions will be consistent enough with the development of NEM that the IRP, or certain elements of the IRP, can be used for assessing the cost impacts of NEM.

result in the shifting of costs from NEM customers to NEM customers, or that these results could not inform subsequent rate design determinations.

Q. Please summarize your recommendations.

A. I continue to stand by all of the recommendations provided in my direct testimony. In particular:

- The Commission should re-affirm that a cost-benefit analysis should be conducted separately from rate design determinations, and clarify that rate design alternatives should be considered *in light of* the results of the benefit-cost analysis.
- The Commission should require that the NEM cost impact analysis be based on net present value of revenue requirements, consistent with the conventional practice of evaluating all types of supply-side and demand-side resources in Utah.
- The Commission should clarify that lost revenues from distributed generation resources should not be included in the cost impact analysis in any way.
- The Commission should require the Company to conduct a rate impact analysis, which does account for lost revenues and cost shifting, to indicate the extent to which customers who do not install distributed generation resources might incur costs from those who do.

Q. Does this conclude your sur-rebuttal testimony?

A. Yes, it does.

DIRECT TESTIMONY OF ASHLEY C. BROWN

On Behalf of Arizona Public Service Company

Docket No. E-00000A-14-0023

EXHIBIT

APS-8

ADMITTED

APS EXHIBIT 8

February 25, 2016

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DIRECT TESTIMONY OF ASHLEY C. BROWN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Ashley C. Brown. I am Executive Director of the Harvard Electricity Policy Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a "think tank" on electricity policy, including pricing, market rules, regulation, environmental and social considerations. HEPG, as an institution, never takes a position on policy matters, so my testimony today represents solely my opinion, and not that of the HEPG or any other organization with which I may be affiliated.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am an attorney with extensive experience in infrastructure, especially energy and regulatory matters. I served 10 years as a Commissioner of the Public Utilities Commission of Ohio (1983-1993), where I was appointed and re-appointed by Democratic Governor Richard Celeste. I also served as a member of the NARUC Executive Committee and as Chair of the NARUC Committee on Electricity. I was a member of the Advisory Board of the Electric Power Research Institute. I was also appointed by the U.S. Environmental Protection Agency as a member of the Advisory Committee on Implementation of the Clean Air Act Amendments of 1990, where I served on the subcommittee charged with implementing emissions trading. I am also a past member of the Boards of Directors of the National Regulatory Research Institute and the Center for Clean Air Policy. I have served on the Boards of Oglethorpe Power Corporation, Entegra Power Group, and e-Curve, and as Chair of the Municipal Light Advisory Board in Belmont, MA. I serve on the Editorial Advisory Board of the Electricity Journal.

I have been at Harvard continuously since 1993. During that time I have also been Senior Consultant at the firm of RCG/Hagler, Bailly, Inc. and have been Of Counsel to the law firms of Dewey & LeBouef and Greenberg Traurig. I have also taught in training programs for regulators at Michigan State University, University of Florida, and New Mexico State University (the three NARUC sanctioned training programs for regulators), as well as at Harvard, the European Union School of Regulation, and a number of other universities throughout the world. I have advised the World Bank and the Inter-American Development Banks on energy regulation and have advised governments and regulators in more than 25 countries around the world, including Brazil, Argentina, Chile, South Africa, Costa Rica, Zambia, Tanzania, Namibia, Ghana, Mozambique, Hungary, Ukraine, Russia, India, Bangladesh, Saudi Arabia, Indonesia, and the Philippines. I have written numerous journal articles and chapters in books on electricity markets and regulation, and I am co-author of the World Bank's *Handbook for Evaluating Infrastructure Regulatory Systems.*

I hold a B.S. from Bowling Green State University, an M.A. from the University of Cincinnati, and a J.D. from the University of Dayton. I have also completed all work, except for the dissertation, on a Ph.D. from New York University. My current CV is provided as Attachment ACB-1DR.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. Yes. I submitted Surrebuttal Testimony recently in the UNS Electric Docket No. E-04204A-15-0142. I have also testified before FERC and various state commissions as well as before Congressional and state legislative committees.

Q. ON WHOSE BEHALF DO YOU OFFER TESTIMONY?

A. On behalf of the Arizona Public Service Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain why regulators should view "value of solar" (VOS) analyses with a great deal of skepticism. It is an approach to pricing that is completely inconsistent with the two tested and proven methods of pricing electricity: costs and/or markets. Most advocates for a VOS approach do not even suggest that it is a pricing methodology that should be broadly applied, but seek to use it for the sole purpose of guiding (or perhaps actually setting) the price of rooftop solar, while pricing every other generating resource, including large scale renewables, using the traditional basis of costs and/or market. That, of course, would result in a discriminatory, largely incoherent, approach to pricing in the increasingly competitive electricity market, and have potentially disruptive effects on the overall efficiency of the power sector. VOS approaches are, as will be shown below:

- highly subjective;
- focused on generalities and largely lacking in the granularity demanded by the complexities of the electric sector;
- arbitrary and policy presumptive about selecting which externalities to consider; and
- often devoid of such critical contexts as costs, markets, technology evolution, and the full range of options in the marketplace.

In short, the value of a VOS analysis is, at best, highly marginal. It is, in the ultimate irony, eerily reminiscent of a major policy mistake in the power sector less than three decades ago.

Q. WHAT IS YOUR OPINION OF "VOS" ANALYSIS, GENERALLY?

A. I have serious reservations about the whole notion of VOS analysis; reservations that go well beyond any disagreements about the methodology used in particular studies. I question whether "VOS" analysis is a technique that should be used at all because of its inherent vulnerability to distortion and to the extent it is applied to distributed solar and not to other resources, it is already a skewed, market distorting, analysis.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony:

- Establishes a benchmark through a brief review of the two bases of traditional pricing: markets and costs;
- Examines the historical parallels of Public Utility Regulatory Policies Act (PURPA) implementation, reviewing the problems of "avoided costs" analysis under PURPA, which give a good picture of the kinds of problems "value" analysis may also encounter;
- Discusses the problems of VOS analysis, progressing from the most general to the most particular, as follows:
    - Problems inherent in the idea of "VOS" analysis;
    - Common conceptual problems in framing approaches to "VOS" analysis;
    - A review of the specific VOS categories proposed by IREC; and
    - A review of four "VOS" studies, which illustrate key issues related to VOS analysis;
- Discusses some of the policy implications of the problems with VOS analysis; and

- Concludes with some high-level recommendations to the Commission about how VOS studies should (and should not) be used in decision-making.

II. THE BENCHMARK: MARKET PRICING AND COST-BASED PRICING

Q. IN YOUR VIEW, WHAT IS THE BEST WAY TO ESTABLISH PRICES?

A. Optimally, prices should be established by market forces. This is not always possible. Where market imperfections exist, the discipline of a competitive market is missing, and it is appropriate to regulate based on costs in order to best replicate what would have happened if the market were shorn of its imperfections. Prices determined by a competitive market or derived from cost-based regulation are essentially subject to an external discipline that should both result in efficient resource decisions that are devoid of arbitrary or "official" preferences. Subjective consideration of the "value" of particular technologies and where they may rank in the merit order of "social desirability" effectively removes the discipline that is more likely to produce efficient results. Whereas both the marketplace and transparent cost-based regulation are likely to produce coherent pricing that allows us to enjoy a degree of comfort knowing that efficient performance will likely lead to productivity, subjective consideration of soft criteria, like a laundry list of "values" of solar, independent of any comparison with other resources, are a step away from coherence, efficiency, and consumer benefits.

III. HISTORY: PURPA AND THE PITFALLS OF 'AVOIDED COSTS'

"Those who don't know history are doomed to repeat it." George Santayana

Or, "Hegel remarks somewhere that all great world-historic facts and personages appear, so to speak, twice. He forgot to add: the first time as tragedy, the second time as farce." Karl Marx

Or, "Déjà vu all over again." Yogi Berra

Q. WHAT IS THE RELEVANCE OF HISTORY TO THE VOS DISCUSSION?

A. The debate over resource value and how to assess it is not new. For those of us who were involved in the power sector in the efforts to implement certain aspects of the Public Utilities Regulatory Practices Act (PURPA) in the 1980's, this entire VOS discussion is pure déjà vu. We have the real benefit of knowing what the outcome was, so we can use that knowledge to avoid repeating the policy/pricing errors.

Many advocates of VOS approaches, however, would have us repeat the same mistakes made just a generation or so ago. The attempt at the time was to administratively impose prices without regard to costs or markets, to somewhat arbitrarily try to monetize some externalities and not others, to impose cross subsidies or skew competition to achieve "desired" outcomes in technology and market position, and to define "avoided costs" in ways that were often less reflective of the economics than of predetermined policy biases. The results were arbitrarily high, or in other cases, arbitrarily low, figures for avoided costs; stranded assets and/or forfeiture of potentially valuable assets; power plant contraptions designed to take advantage of policy prescriptions rather than efficiency and productivity potential; and a highly inefficient market for generation that administratively determined winners and losers.

The "avoided costs" debate was not exclusively focused on one resource, as the VOS debate today exclusively focuses on rooftop solar. The concept, however, and to a remarkable degree the "calculations" and reasoning, were substantially the same then as they are now. The results of the 1980's experience was that the FERC was forced to intervene and impose a market-based bidding regime to discipline a process that had clearly gone awry.

So why are we doing this again, in the time when we have smart technology, a highly competitive market in generation, much smarter prices, and a completely changed environmental context? We have evolved significantly, and yet, with the use of VOS analysis, we are at risk of replicating a process whose ending, we all know, was most unhappy.

Q. WHAT HAPPENED IN THE 1980S?

A. In 1978, Congress enacted PURPA. Among other things, PURPA encouraged the development of alternative power, including renewable energy and cogeneration, by requiring utilities to purchase energy and capacity from qualifying facilities (QFs) at their incremental or avoided costs. "Avoided costs" was defined as: "[T]he incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source."[1]

FERC further required that each state define the appropriate avoided cost rate, and allow smaller QFs to access that rate as a "standard offer rate" (larger QFs could be required to go through a process of individual negotiation.)[2] The implementation of PURPA was largely left to the states, although FERC retained certain oversight and definitional powers.

Q. WHAT WAS THE EXPERIENCE WITH "AVOIDED COSTS" UNDER PURPA?

A. "Avoided costs," originally, were a kind of very simple value analysis, including only avoided energy and capacity costs. Over time, however, states not only took quite diverse paths to ascertaining the avoided costs, but many went beyond energy and capacity and factored environmental and other externalities into their calculations. The calculations were also handicapped by the fact that wholesale markets and transmission

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[1] 18 CRF §292.101(b)(ii)(6) (Public Utility Regulatory Policies Act of 1978).

[2] Fox-Penner, Peter, Will Forman, Bob Mudge, Jens Schoene, Sanem Sergicic, and Bruce Tsuchida. *Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area.* The Brattle Group, July 2015, p. 6. *Please see:* http://www.brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado's_Service_Area.pdf?1436797265.

pricing, while in existence, were by today's standards rather primitive and yielded incomplete and constrained cost and market data. The absence of sophisticated pricing in the wholesale energy market was an important factor in this complexity, resulting in multiple competing methods for determining the cost savings from energy provided. Further complicating matters were attempts to offer long-term contracts to QFs, which necessitated assumptions about fuel costs, factoring in future, but then unknown, environmental regulation, the effects of enabling new technologies in the marketplace, alleged system benefits, and many other factors projected well into the future.[3] It should also be noted that states were all over the board on how they considered existing capacity in determining which costs were avoidable and which were not.

Given all of those uncertainties, as well as the resource and technology biases in various jurisdictions, not surprisingly, the resulting "standard offer rates" varied widely among states. Some states used very conservative avoided cost estimates; others were extremely generous. In a few states, extremely generous standard offer rates resulted in a flood of QFs from which utilities were required to purchase power at prices many utilities claimed were far above their actual avoided costs. While many states tried to monetize all of the benefits or costs associated with avoided cost calculations, the resulting prices were the result of administrative discretion largely undisciplined by either costs or markets. Worsening the problem, avoided cost projections made near the height of the energy crisis seriously overestimated the future prices of oil and natural gas, with the result that many utilities entered into long-term agreements to purchase power under PURPA that were based on wildly overestimated values for future "avoided costs."[4] The result was chaotic. In many jurisdictions QF's contracts were highly priced and therefore

[3] In most cases, it was the regulators who did the calculations, but, occasionally it was the legislatures. New York, for example, had a statute that said that QF contracts had to be at least 6 cents per kWh. New York Public Service Law §66-c(2)(a).
[4] Basheda, Greg, Frank Graves and Philip Hanser. *PURPA: Making the Sequel Better than the Original.* Prepared for EEI (December 2006) at pgs. 12-13. *Please see:* http://www.eei.org/issuesandpolicy/stateregulation/Documents/purpa.pdf.

attracted many investments, the totality of which drove up prices for consumers. By the 1990's, newspapers were reporting billions of dollars of additional costs going to support poorly maintained projects producing power at as much as five times the going rate.[5] In other states, the avoided cost was set so low that very little non-utility generation materialized.

FERC's response to the situation evolved over time. In 1998, in response to appeals from New York utilities arguing against New York's intentional adoption of a rate well above actual "avoided costs," FERC changed its original position to rule that states could not set above-market avoided cost rates, citing "the proliferation of qualifying facilities" as one of the reasons for this change.[6] Similarly, FERC eventually gave up on trying to correct and improve administrative avoided cost determinations, beginning with a Notice of Proposed Rulemaking in 1988, but by 1998 abandoning this effort and instead endorsing state efforts to use competitive procurement mechanisms to establish costs.[7] And, in fact, perhaps in part as a reaction to the obvious problems of PURPA, by 1998, utility restructuring was underway in many parts of the country.[8]

Thus, the use of highly subjective criteria for pricing generation proved to be a very serious policy mistake, which, while well intentioned, had the adverse effect of imposing unreasonable prices (too high in some states and too low in others), and misallocating capital in ways that rendered markets less efficient and failed to incent productivity gains. The lessons of that experience were costly, but once they were fully

[5] Bailey, Jeff. "Carter-era Law Keeps Price of Electricity Up in Spite of a Surplus." *Wall Street Journal* 17 May 1995.

[6] *Re Orange & Rockland Utilities, Inc., Rockland Elec. Co., Pike County Light & Power Co.*, 92 P.U.R.4th 1 (F.E.R.C. Apr. 14, 1988).

[7] *Admin. Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, & Interconnection Facilities,* 84 FERC ¶ 61265, 62300 (F.E.R.C. Sept. 21, 1998).

[8] "Indeed, restructuring itself may have been partly induced or encouraged by the sometimes imbalanced and uneconomic results of PURPA. There is a strong correlation between the states with the largest PURPA supply and their early pursuit of retail access." Basheda, Greg, Frank Graves and Philip Hanser. *PURPA: Making the Sequel Better than the Original.* Prepared for EEI (December 2006) at p. 2.

understood, we adhered to policies in which prices were highly disciplined by increasingly competitive and sophisticated markets, or, where a market failed to accomplish that, by cost based regulation, both of which are highly disciplined and far less vulnerable to subjective manipulation.

Q. SO WHY IS THE PURPA EXPERIENCE RELEVANT TO THE IDEA OF A "VOS" ANALYSIS?

A. The attempts to use laundry list, out of context, VOS analyses,[9] either to set rates, or even as a guideline to assessing the reasonableness of prices (e.g., those under Arizona's net metering regime) is, for the most part, an effort to replicate and reinstate, albeit solely for the advantage (or in a few cases the disadvantage) of a single technology (rooftop solar), a pricing methodology that proved to be highly undisciplined, misallocated capital in inefficient ways, distorted prices for both consumers and producers, skewed both energy and capacity markets, effectively chose winners and losers on an administrative rather than performance basis, and ultimately led to FERC having to intervene in matters heretofore subject to state regulation.

Another dynamic of the VOS debate that is reminiscent of the PURPA implementation issues of the 1980's is the use and abuse of monopoly power. Rooftop solar interests routinely argue that utilities want to preclude competition from rooftop solar in order to preserve their monopoly. While I do not subscribe to that point of view, it is worth noting that there is a supreme irony in that contention. Solar advocates who call for the use of VOS analysis in either guiding or actually setting the prices for rooftop solar, are, in fact, trying to take advantage of monopoly power and lack of customer choice to

[9] By "laundry list, out of context, VOS analyses," I am not trying to devalue rooftop solar, but, rather, I am referring to the common genre of efforts that monetize a long laundry list of "values," based on inherently unreliable long-term projections of value, without any reference to other competing options to attain the same values more cost-effectively. What I am referring to throughout this paper when I refer to "VOS" analysis is this kind of laundry list in a vacuum (derived in a carefully selected, arbitrary, and often biased way) approach, not efforts like those of witness Albert to evaluate rooftop solar within the full context of other competing technologies.

enable the price paid for rooftop solar to be escalated above market or costs, by administratively and creating highly selectively adders to the price paid for rooftop solar to reflect claims of non-economic or fully internalized "benefits," while at the same time ignoring similar non-economic or non-internalized costs. No competitive or cost-based pricing regime would allow that to happen. But it is doable in a monopoly setting, and that is precisely what a number of the VOS studies are advocating, much like some interest groups did on the PURPA debates of the 1980's. The irony, of course, is that those advocating such an approach are, in fact, trying to claim for themselves the advantages of monopoly power. In short, much like in the PURPA debate in the 1980s, certain new entrants into the market are not trying to compete on a level playing field, but rather are trying to take a piece of that monopoly power to get far above-and out-of-market prices for their product. So the question of the use and abuse of monopoly power is very much a part of this issue.

Q. SO ARE YOU SAYING "VOS" ANALYSIS IS PURPA'S "AVOIDED COST" ANALYSIS ALL OVER AGAIN?

A. VOS analyses have all of the problems of historical avoided cost analyses, and more. VOS studies/arguments, are, like PURPA implementation prior to FERC's imposition of marketplace discipline into pricing, an attempt to administratively and selectively choose criteria to alter pricing that would otherwise be set by either the market or costs. VOS approaches also can lead to the use and abuse of market power in order to benefit particular products and services.

Historically, we have used two methods of pricing electricity, cost-based regulation and competitive markets. PURPA modified those a bit by offering a variation of cost-based regulation, namely avoided costs. That in itself, as I discuss, created many problems. The idea of a "value" analysis takes matters even further. We have never used subjective notions of "value" to set prices. There is good reason for that. Value is subjective, easily manipulated, generally non-transparent, and lacks the discipline imposed by markets and cost-based regulation. There is also little or no precedent in U.S. regulation, or regulation anywhere, to use a "value of" approach to one resource, while applying the rigors of markets and/or regulation to other competing resources. It has been well-recognized that such widely varying methods of pricing applied to competing resources has adverse consequences, such as reducing market efficiency, distorting price signals, and misallocating capital. The history of PURPA teaches us the pitfalls of "avoided cost" analysis. If anything, a "VOS" analysis, straying even farther from the discipline and transparency of markets and cost-based pricing than an avoided cost analysis, has the potential to lead to even more problems than those experienced during the implementation of PURPA.

In short, we know how the VOS movie will end, so why are we going to replay it? More specifically, why would we want to play it out in the context of 2016, when we have much more sophisticated technology and far more efficient energy markets, both of which enable smart and precise prices to be set by the markets, or if need be, by cost of service regulation.

IV. WHAT'S WRONG WITH A "VOS" ANALYSIS?

Q. CAN YOU GIVE AN OUTLINE OF WHAT YOU SEE AS THE PROBLEMS OF VOS ANALYSIS?

A. Yes. I organize my discussion of the problems of VOS analysis in order from the most general and inherent to more and more specific issues, ending with an overview of some key problems in four specific VOS studies.

i. Problems that can't be fixed: "VOS" analysis is inherently subjective, readily manipulated, and inherently skewed

Q. WHY DO YOU SAY THAT "VOS" ANALYSIS IS SUBJECTIVE AND READILY DISTORTED?

A. Studies of the "VOS" are highly subjective and readily manipulated because there is no established methodology, and, furthermore, given the complexity of the analyses needed to assess all the various "VOS" claims, no analysis can effectively avoid the need to make multiple subjective analytical judgments. Thus, every such analysis is subject to the biases and policy predispositions of the authors and/or sponsors of such studies. This reality is well illustrated by the extraordinarily wide variance in the conclusions of such studies. The range is dramatic, with a VOS study in Louisiana which found a negative value, while a VOS study in Maine calculated a value of 33.7 cents/kWh.[10,11,12]

The reason we see such wide variation is that VOS studies are inherently subjective and arbitrary. Study findings are easily distorted in subtle ways to match any agenda. There is no commonly accepted methodology for doing VOS analysis. Indeed, there are not even any commonly accepted criteria to assess in ascertaining value.

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[10] Dismukes, David E. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. Prepared on behalf of the Louisiana Public Service Commission.* Prepared on Behalf of Louisiana Public Service Commission Draft, February 27, 2015. *Please see:* http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5

[11] Grace, Robert C., Philip M. Gruenhagen, Benjamin Norris, Richard Perez, Karl R. Rabago, and Po-Yu Yuen. *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission. Revised April 14, 2015. *Please see:* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

[12] To put the 33.7 cents /kWh valuation in perspective, that number is roughly double the full retail rate of Maine's largest electric utility. In other words, the authors of that study calculated that the "value" of the energy produced by each rooftop solar installation is worth double the full delivered cost of electricity. That is the equivalent of saying that the value of a part of a product is worth double the value of the entire product.

Q. IS THE FREQUENTLY-CITED IREC "GUIDEBOOK" A HELPFUL STEP TOWARDS ESTABLISHING AN UNBIASED METHODOLOGY?

A. No. The problem of lack of a standard methodology was recognized by a leading solar energy advocacy group, Interstate Renewable Energy Council (IREC), which tried to fill that vacuum by publishing *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* It offers a list of criteria that I analyze in my testimony below. Instead of solving the problem, however, IREC proves my point. IREC's criteria constitute a self-selected, self-serving, heavily-biased laundry list of subjects that, remarkably, fails to include costs and market prices, as well as attributes that might diminish value, such as subsidies/cross-subsidies, job losses as well as the job gains claimed, risks associated with using rooftop solar to reduce carbon, market distortions, etc. IREC's *Regulator's Guidebook* also fails to include other obvious subjects any credible study would have to examine, such as impact on merit order dispatch, the energy resource mix in the state being studied, disparate social impact of rooftop solar subsidies, market effects, impact on energy efficiency, a comparison of costs with other resources that can accomplish similar objectives, environmental considerations beyond simply carbon, full cycle impacts (i.e., manufacture through generation) of solar panels and installations. An even-handed, disciplined, and thorough analysis would have to include these variables, along with an almost infinite host of others. And IREC does not even try to make the case for why rooftop solar prices should either be guided or actually set by VOS, while all other resources should be priced by cost or market. Thus, what purports to be a methodological guide is, in fact, a transparent example of how to manipulate VOS studies to validate a predetermined outcome.

Given the highly subjective, often biased, nature of VOS analysis, it is hardly surprising that one finds an extraordinarily wide variance in conclusions. Moreover, it is fairly clear that the biases of whoever is authoring and/or paying for these reports bring heavy influence to bear on not only the conclusions, but, in fact, on how the studies are carried out and what factors are included and excluded from consideration. My point about all this is that this kind of analysis, in practice, is completely subjective; you could drive up the VOS, you could drive down the VOS-it's easy to manage the results in either direction. This is one of these "garbage in, garbage out" ways of analyzing. VOS analyses are inherently skewed.

Q. WHY DO YOU SAY VOS ANALYSES ARE "INHERENTLY SKEWED?"

A. VOS studies are technology specific (almost always limited to rooftop solar). This makes them one-sided. As noted earlier, the studies never answer the question of why, if we would use value-based pricing for rooftop solar why we don't use value-based pricing for every other resource? Why are we singling out rooftop solar? VOS studies rarely, if ever, look at the opportunity costs associated with spending money on rooftop solar, as opposed to using that money on something that produces energy and/or reduce emissions more efficiently, incentivizes rooftop solar to be more efficient and more productive, and promotes overall market efficiency and system benefits.

If we're going to use a VOS analysis to establish prices, then why in the world don't we do that for nuclear, coal, natural gas, wind, and every other resource? Or, for that matter, establish a value for the grid itself? It is very difficult to discern any justification for singling this technology out for an analysis that is completely different from and, frankly, historically foreign to, the way that we set prices for energy in the U.S.[13]

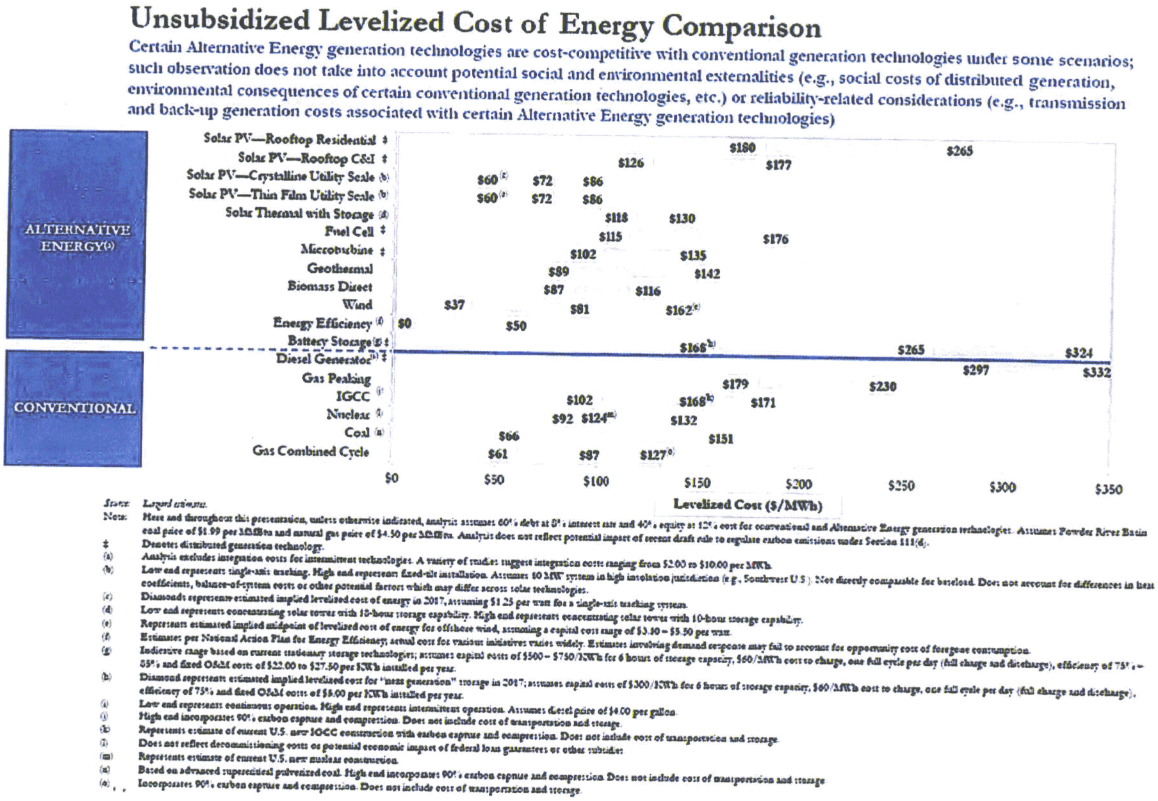
Q. CAN YOU GIVE AN EXAMPLE OF HOW THE ONE-SIDED FOCUS OF VOS ANALYSIS CAN CONTRIBUTE TO BAD POLICY?

A. A classic example of the kind of problem this single focus of "value" analysis relates to the question of whether distributed solar has extra value because it does not emit carbon. While rooftop solar does not, in the process of producing energy, emit carbon, VOS

[13] At a minimum, if one were determined to pursue a value analysis (which I do not in any case recommend), competing renewables should be considered.

studies do not even address the question of its cost of doing so in comparison with other non-emitting energy sources, despite the fact that much has been written on the efficiency of using various methods to reduce carbon emissions, and distributed solar generally ends up at the low end.

Rooftop solar is the most expensive form of generation widely used today. The chart that follows illustrates that point:[14]



No less an environmental advocate than Amory Lovins acknowledges that solar energy (even grid-scale solar energy) is less cost effective than wind and hydro in terms of reducing carbon emissions.[15] An interesting dialogue occurred recently between Charles Frank, an economist at Brookings, and Amory Lovins of the Rocky Mountain Institute, based on an effort by Mr. Frank to develop an analysis of the cost-effectiveness of solar

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[14] *Lazard's Levelized Cost of Energy Analysis, Version 8.0*. 2014. p. 2. *Please see:* https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.

[15] Lovins, Amory B. "Sowing Confusion about Renewable Energy." *Forbes* 5 August 2014.

PV as a carbon reduction tool, taking into account not only the levelized cost of energy, but some of the considerations about peak production and effects on the functioning of the overall energy system discussed above.[16] Their dialogue, while contentious on many points, includes, on both sides, numbers that show agreement on the fact that solar is the least cost effective of all commonly-deployed renewable resources in reducing emissions.[17]

A recent study by the Brattle Group comparing generation costs of grid-scale and rooftop solar in Colorado confirms that rooftop solar is likely even less efficient at reducing emissions than grid-scale solar: "Simply stated, most of the environmental and social benefits provided by PV systems can be achieved at a much lower cost at grid-scale than at residential-scale."[18]

That is, of the renewable generation choices commonly available, rooftop solar is the highest cost way of reducing carbon emissions. Nevertheless, VOS papers almost always ascribe significant value to the carbon reduction value of rooftop solar. What is never asked, however, is how that value compares with the stepped up utilization of grid-scale renewable or energy efficiency in reducing emissions, and what the opportunity cost is for diverting capital from more efficient means of carbon reduction to the less efficient means of rooftop solar. What most, if not all of these studies lack, is

[16] *See* Frank, Charles R. Jr. *The Net Benefits of Low and No-Carbon Electricity Technologies.* Global Economy and Development at Brookings Working Paper 73, May 2014. *Please see:* *http://www.brookings.edu/~/media/Research/Files/Papers/2014/05/19%20low%20carbon%20future%20wind%20solar%20power%20frank/Net%20Benefits%20Final.pd;* and Lovins, Amory. *An initial critique of Dr. Charles R. Frank, Jr.'s working paper 'The Net Benefits of Low and No-Carbon Electricity Technologies,' summarized in The Economist as 'Free exchange: Sun, wind and drain.'* Rocky Mountain Institute, 2014. *Please see:* http://www.rmi.org/Knowledge-Center/Library/2014-21_Frank-Rebuttal.

[17] As Frank puts it, even after addressing Lovins' criticisms, "Wind continues to rank number four and solar ranks number five by a large margin." Frank, Charles. *"Alternative Energies Debate—The Net Benefits of Low and No-Carbon Electricity Technologies: Better Numbers, Same Conclusions"* September 4, 2014. http://www.brookings.edu/blogs/planetpolicy/posts/2014/09/04-low-carbon-tech-lovins-response-frank. Lovins, Amory B. "Sowing Confusion about Renewable Energy." Forbes 5 August 2014.

[18] The Brattle Group Study at 3.

context; VOS study authors, as general rule, ignore context and view rooftop solar as if it exists in an almost perfect vacuum.

Q. WHAT IS THE RISK OF STICKING WITH AN APPROACH THAT ONLY LOOKS AT THE "VALUE" OF ONE RESOURCE?

A. A major risk is losing sight of the big picture, and making decisions without considering the overall context and alternatives. Whatever "value" you are pursuing, you should think about multiple ways to get there, and what the most cost-effective approach will be to obtain the value in question. I discuss the huge example of carbon emissions. The problem with promoting rooftop solar as a solution to carbon emissions is not only inefficiency, but that doing so is a threat to the goal itself. If you choose pathways that are not cost effective, if effective at all, you run the very real risk of exhausting resources and public support without really impacting the problem. It is important to note that not a single VOS paper I have reviewed even looks at this very critical question.

i. <u>Foundational problems that can throw off the whole framework of a study: Common conceptual problems in framing approaches to "VOS analysis;"</u>

Q. TURNING FROM THE MOST GENERAL LEVEL OF PROBLEMS WITH THE THEORY OF A VOS ANALYSIS TO MORE SPECIFIC LEVELS, ARE THERE RECURRING PROBLEMS YOU OFTEN SEE IN FRAMING APPROACHES TO A VOS ANALYSIS?

A. Yes, and I will detail some of them below. Note that this is not an exhaustive list—many other issues, such as choice of discount rate, estimates of likely rooftop solar penetration in the future, etc., have been raised as at least needing careful treatment. The issues below, in my opinion, are some of the most fundamental conceptual problems:

- VOS studies are often unclear about the question they are answering;
- VOS studies often struggle with how to forecast costs and benefits into the future;

- VOS studies are sometimes not realistic (or even consistent) about what marginal power will be offset by rooftop solar;
- VOS studies often fail to account for costs, as well as benefits; and
- VOS analysis generally ignores the regressivness of existing net metering policies.

Q. WHY DO YOU SAY THAT VOS STUDIES ARE OFTEN UNCLEAR ABOUT THE QUESTIONS THEY ARE ANSWERING?

A. To ask "what is the value of solar?" is not in itself a complete question. You need to complete the thought by specifying whose value you are asking about, and in what policy context. Does the study seek to establish value according to rooftop solar customers? All customers? The rooftop solar industry? The utility? The state as a whole? The general public? There is usually a policy reason behind this question, and being clear about what policy question is being answered is important. Which costs and values are appropriate to consider will vary, depending on what you are examining.[19] Such differences in perspective are behind certain disagreements about specific elements of the VOS, such as whether payments to net-metering customers count as a cost of rooftop solar from the perspective of the utility and of non-net metering customers, these payments certainly do. On the other hand, a study of the VOS to rooftop solar customers would include net metering payments.

The question gets a little tricky if the study seeks to establish benefits for a whole state (which many do). Rooftop solar customers are part of the state, so one might argue that benefits to them should count in the analysis. (Analyses that include benefits to solar customers, should of course, include the costs they incur to install and maintain solar

[19] Let me acknowledge here that I am not the first person to point this out. The need to clarify "stakeholders" is often advised. But, judging from some of the VOS studies I have reviewed, this is a rule often honored in the breach.

panels as well). This is where understanding the policy question you want to answer becomes important. You might do an analysis including costs and benefits to solar customers if the question you want to answer is, "Does support for rooftop solar improve the well being of the state as a whole, disregarding whether it transfers wealth from non-rooftop solar to rooftop solar customers or causes other wealth transfers within the state?" On the other hand, much more often, the study is being done to answer the implicit or explicit question: "Is this investment in rooftop solar, an investment that solar customers make independently, outside the planning process of the utility, beneficial to the rest of the state? (And, if so, by how much?)," and the related question, "What is the rest of the state getting in return for its support of rooftop solar?" If this is the question you are trying to answer, costs and benefits to solar customers themselves must be excluded.

Similarly, it matters who is asking the question. If a public service commission is asking the question as part of a review of their own policies in regard to rooftop solar, one argument is that the answer is likely to be most helpful if it excludes elements over which the Commission has no control-in this case, both the investment decisions made by rooftop solar customers, as well as state and federal solar energy subsidies. On the other hand, if you believe that state subsidy expenditures are caused by net energy metering policies (that is, the state offers a tax incentive for rooftop solar investment, but it won't be used by customers without the additional support of net energy metering), then you might choose to include state subsidy costs. In many states, that decision may make the difference between finding net costs or net benefits for rooftop solar. This was the case in the Louisiana study conducted by Dismukes, and discussed later in my testimony, notable for finding the "VOS" to be negative.

Q. WHY DO YOU SAY THAT VOS STUDIES STRUGGLE WITH HOW TO FORECAST COSTS AND BENEFITS?

A. Most analyses of the VOS, recognizing that rooftop solar systems are supposed to have a lifetime of at least twenty years, aim to do more than assess the value of a rooftop solar system in its first year of operation, or the value of rooftop solar in a state in one year.

The problem here is not the conceptual idea that the VOS might change over time, but rather the fact that layering the uncertainty of future predictions on top of the inherent complexity of presently valuing solar multiplies the ways in which analysis can go wrong. Furthermore, the different approaches studies take to this problem make it hard to meaningfully compare study results.

Marginal price comparisons (fuel price comparisons) for solar vs. fueled generation are increasingly uncertain the farther out in time they go. Today, analyses done as recently as a year ago already look dated, due to their assumptions about increasing natural gas prices. As recently as January, 2015, the EIA was forecasting average 2016 natural gas prices at the Henry Hub of $3.86/MMBtu.[20] Although it is of course too early in the year to say with certainty that this forecast is wrong, it is looking unlikely that average prices for 2016 will be anywhere near predicted levels-so far, they have hovered not far about $2/MMBtu (with one notable dip below the $2 mark).[21] Using long-term price forecasts for energy, particularly for our fuel prices, is notoriously unreliable.

Some studies do a better job of handling future uncertainties than others. Let me contrast VOS studies in Minnesota and Maine on this. Minnesota explicitly calls for an annual adjustment, and one factor to be adjusted is the cost of fuel. Maine, on the other hand,

[20] *Platts*, US EIA sets 2016 natural gas price forecast at $3.86/MMBtu. January 13, 2015. *Please see:* http://www.platts.com/latest-news/natural-gas/washington/us-eia-sets-2016-natural-gas-price-forecast-at-21834965.

[21] *EIA*, Henry Hub Natural Gas Spot Price. *Please see* https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm.

assumes a 3% or 4% increase in natural gas prices every year for 25 years (based on NYMEX futures and EIA projections).[22]

In fact, of course, we don't know what will happen with these prices. 25-year forecasts, regardless of who they come from, are notoriously inaccurate. In fact, the only thing you know about those 25-year fuel forecasts is that they're wrong. Minnesota's VOS approach to the fuel price issue is more sensible in that it recognizes this uncertainty and, rather than relying on unreliable long-term forecasts and ignoring market forces, proposes adjustments on an annual basis to reflect what's actually going on in the marketplace.

Projections of future values need to be treated with caution. Recent experience has dramatically demonstrated how wrong projections of ever-increasing natural gas prices can be. Nor is there much certainty about the likely costs of future CO2 allowance prices (there seems to be even less certainty about this since the Supreme Court granted a stay on implementation on the CPP).

Q. WHY DO YOU SAY THAT VOS STUDIES ARE SOMETIMES NOT REALISTIC (OR EVEN CONSISTENT) ABOUT WHAT MARGINAL POWER WILL BE OFFSET BY ROOFTOP SOLAR, AND WHY IS THIS A FOUNDATIONAL PROBLEM?

A. With respect to the many dimensions of a VOS analysis (energy value, capacity value, and environmental value, for example), you have to look at what's being dispatched and what marginal resource is being displaced. If the solar resource is modeled as displacing relatively clean energy, as opposed to coal, then the cost of energy you are displacing

[22] Fuel price projections are commonly used in the power sector for planning purposes. But the Maine study suggests is that they should be used for purposes of pricing long term contracts with rooftop solar providers, particularly when the price of the energy procurement by the utility is not further disciplined by a competitive solicitation. In short, many VOS studies, and the one in Maine quite notably, simply imply that the fuel price is as projected and ignore the competitive market forces that influence the price of every other energy source. This does not reflect market realities. *See Maine Distributed Solar Valuation Study.*

might be higher than if you were displacing coal. But the externality value is a whole lot less, and the study needs to identify that trade off. To actually quantify this trade off, you must get to a high level of granularity in the study.[23]

Maine's study (discussed in more detail below) is a particularly egregious example of doing this wrong. As discussed in more detail below, some parts of the study assume gas is the marginal fuel displaced; other parts assume (improbably) that coal is being displaced. Picking and choosing the marginal power source is another potential source of subjectivity in VOS studies.

Q. WHY DO YOU SAY THAT VOS STUDIES OFTEN FAIL TO ACCOUNT FOR COSTS, AS WELL AS BENEFITS? WHAT COSTS DO YOU HAVE IN MIND?

A. "VOS" analyses also tend to be one dimensional, identifying benefits without balancing that off against related costs. Frequently (though not always), the discussion does not include any serious consideration of costs associated with rooftop solar and policies enacted to support it—lost utility revenues, which must be made up for by non-rooftop solar customers; costs to the rest of the system incurred in order to integrate intermittent renewable energy while keeping power supply steady; the need for additional reserves to back up a pool of generation that can vary unpredictably with the weather;[24] the need to maintain standby generation (spinning and non-spinning reserves) to maintain system frequency, despite solar intermittency; transaction costs; distribution changes required to

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[23] Because most coal fired plants are baseload and not engineered for ramping, and because the natural gas plants are the generating resources typically on the margin, rooftop solar is likely displacing the lower emitting gas plants rather than the higher emitting coal plants. That likelihood is enhanced by the fact that rooftop solar is intermittent. Thus, it is impossible to assign a carbon emissions value without knowing precisely what is being displaced.

[24] "Unexpected short-term changes in solar generation require additional backup capacity to avoid temporary mismatches between supply and demand." Baker, Erin, Meredith Fowlie, Derek Lemoine, and Stanley S. Reynolds. "The Economics of Solar Electricity." American Review of Resource Economics vol. 5 (June 2013), p. 404.

accommodate bidirectional flows; and costs to the economy as a whole (including job losses) associated with higher energy costs.[25]

Q. WHY DO YOU SAY VOS ANALYSIS GENERALLY IGNORES THE REGRESSIVENESS OF EXISTING NET METERING POLICIES?

A. A VOS analysis typically ignores the social impact of policies, such as net metering implemented to support distributed solar. Empirical studies on this subject have indicated that net metering pricing has a regressive social impact.[26] It is, in fact, a wealth transfer from lower-income people to higher-income people. Rarely do you find this wealth transfer assessed in VOS studies. But it is a social cost, and it ought to be assessed. The failure to consider this wealth transfer is part of the selectivity you often see relative to how externalities are included and excluded from VOS studies.

i. Specific problems with IREC's proposed "VOS" categories

Q. HOW DO THE GENERAL ISSUES ABOVE APPLY TO THE ANALYSIS OF SPECIFIC "VALUES" OFTEN ATTRIBUTED TO SOLAR?

A. There are a number of different ways potential benefits and costs are addressed in different studies. In many cases, the "values" proposed are either non-existent, or presented in a one-sided manner that ignores offsetting costs. Even benefits, such as avoided energy costs (which seem undeniable), can be very hard to quantify reliably, especially when attempts are made to look decades into the future. For the purpose of

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[25] *Id.* at 405.

[26] Energy and Environmental Economics, *California Net Energy Metering Ratepayer Impacts Evaluation*. Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 28, 2013); Hernandez, Mari. *Rooftop Solar Adoption in Emerging Residential Markets*. Center for American Progress, May 29, 2014. *Please see:* https://cdn.americanprogress.org/wp-content/uploads/2014/05/RooftopSolar-brief3.pdf; and Hernandez, Mari, *Solar Power and the People: The Rise of Rooftop Solar Among the Middle Class*. Center for American Progress, October 21, 2013. *Please see*: https://www.americanprogress.org/issues/green/report/2013/10/21/76013/solar-power-to-the-people-the-rise-of-rooftop-solar-among-the-middle-class; and Staff Report/Open Meeting Memorandum on Arizona Public Service Company – Application for Approval of Net Metering Cost Shift Solution. Arizona Corporation Commission Docket No. E-01345A-13-0248, September 30, 2013.

this testimony, let me review the categories proposed by the previously referenced IREC Guide—a list frequently mentioned when a "VOS" analysis is urged.

Q. WHAT ROLE DOES ENERGY PLAY IN THE VOS?

A. Avoided energy use is one impact of rooftop solar that seems to have the virtue of being clear and uncontroversial. However, there are often contentious issues regarding how to calculate those energy savings. The issue is whether the savings should be calculated on an average basis, or calculated more precisely by establishing the energy costs saved in the hour the rooftop solar system generates electricity. Since rooftop solar is almost always non-coincident with peak, crediting rooftop solar at average prices fails to precisely capture the market value of the energy. Thus, determining the value of the energy becomes a subject for debate, as we have seen in the recent UNES rate proceeding.[27] Hence, every VOS study will have to make assumptions about how to calculate energy value, and those assumptions are both controversial and can, in and of themselves, be manipulated in order to drive the value calculations up or down.

Moreover, as noted above, the longer such calculations are projected out in time, the greater their potential for distorting value. That risk is not necessarily remedied by the use of futures markets and forecasts of natural gas prices, resources that many VOS analyses rely upon. These are, to understate the point, far from infallible. For example, I don't believe any of them predicted the current natural gas prices of approximately $2/MMBtu. The fact is that the price of energy is in a constant state of hourly flux, but authors of VOS studies typically ignore the realities of those market prices and substitute some proxy that helps achieve a desired outcome.

[27] Arizona Corporation Commission Docket No. E-04204A-15-0142.

Q. WHAT IS YOUR ASSESSMENT OF THE VALUES ASSOCIATED WITH AVOIDED SYSTEM LOSSES AND CONGESTION?

A. Whether or not rooftop solar systems "reduce the amount of energy lost in generation, long distance transmission and distribution" is a fact specific question. It is flat wrong to claim that solar PV systems, ipso facto, reduce losses. On distribution systems, even the theory underlying this claim is controversial among experts. The truthful answer appears to be that sometimes rooftop solar reduces energy losses on the distribution system, but often does not, and, indeed, could in some circumstances actually cause more losses. The validity of the claimed loss avoidance is very situation specific.

With regard to transmission losses, it is certainly true that solar PV on distribution systems does not rely on high voltage transmission. Despite that, rooftop solar does, in fact, impact the transmission system because of its intermittent nature and its steep ramps up and down, which require utilities to be able to quickly bring other resources on line in ways that can have impacts on transmission congestion, depending on the specific configuration of a given system. Rooftop solar also can have very real impact on congestion because the amount of energy being imported or not imported into the low voltage distribution grid inevitably makes its impact felt in the flows on the transmission grid. That value could be positive or negative depending on precisely what is occurring, so the *ipso facto* presumption of a positive value for congestion is simply baseless.[28] The same is true in regard to system losses, at both the distribution and transmission levels.

[28] Congestion is a real cost on all transmission systems. While Arizona is not part of an organized market that explicitly prices congestion, that fact does not alter the reality that congestion costs are incurred.

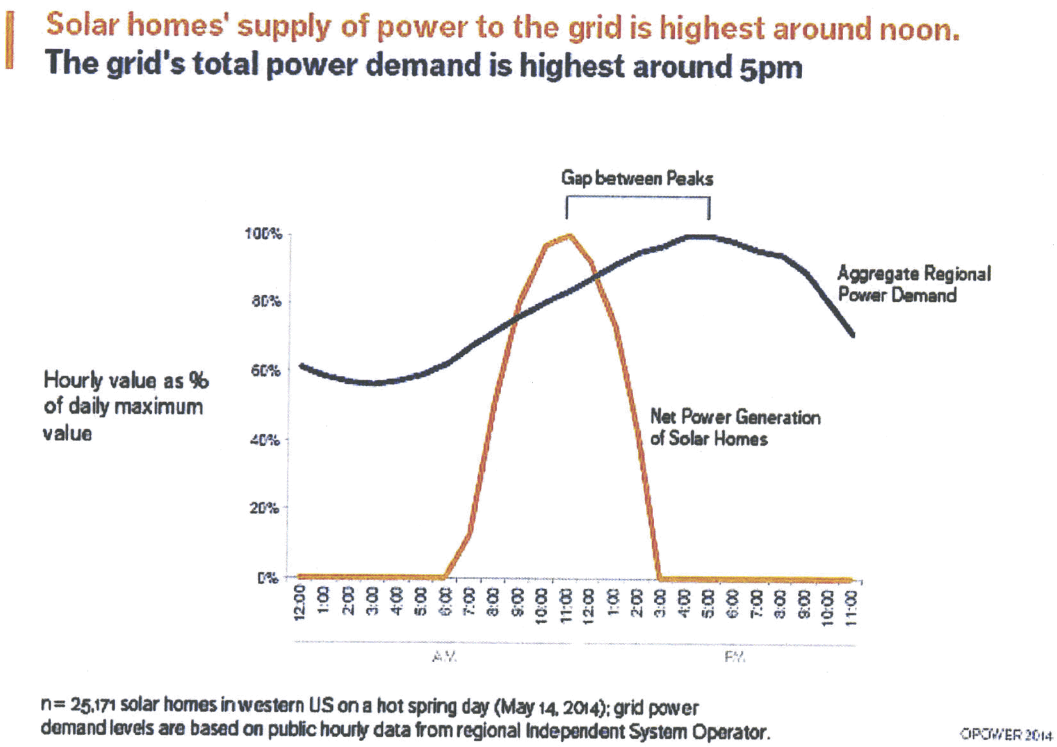
Q. WITH RESPECT TO GENERATION CAPACITY, HOW DO YOU ASSESS THE AVAILABILITY/CAPACITY VALUE OF ROOFTOP SOLAR?

A. Many VOS studies assign a value to the capacity provided by rooftop solar. In some cases, this value is quite large (see the Crossborder Arizona Study discussed below).

But the capacity value of a generating asset is derived from its availability to produce energy when called upon to do so. By its very nature, rooftop solar on its own, without its own backup capacity (e.g., storage), can only produce energy intermittently. It is completely dependent on sunshine in good atmospheric conditions. Unless sunshine is guaranteed at all times at which rooftop solar is called upon to produce, it cannot be relied upon to be available when needed. Moreover, even if all days were reliably sunny, the energy derived from the sun is only accessible at certain times of the day. Utilities, however, are required to serve all of the demand of customers in their service territory at all times. That means utilities must plan for the capacity needed to serve peak demand, largely without regard to the existence of rooftop solar.

The capacity value of rooftop solar is even further diminished by the fact that the presence and potency of sunshine is not coincident with peak demand. Rooftop solar capacity is generally at its peak in the early afternoon, while peak demand occurs later in the afternoon or in early evening.

The chart below prepared by Opower, based on data from California, nicely illustrates what this disjunction looks like:[29]



In the APS territory, as well, the highest demand peak is between 5pm and 6pm in the hottest summer months a time at which solar production is "significantly reduced" from its noon peak.[30] As illustrated in the chart below, elsewhere in Arizona, UNSE sees a similarly late-afternoon peak:[31]

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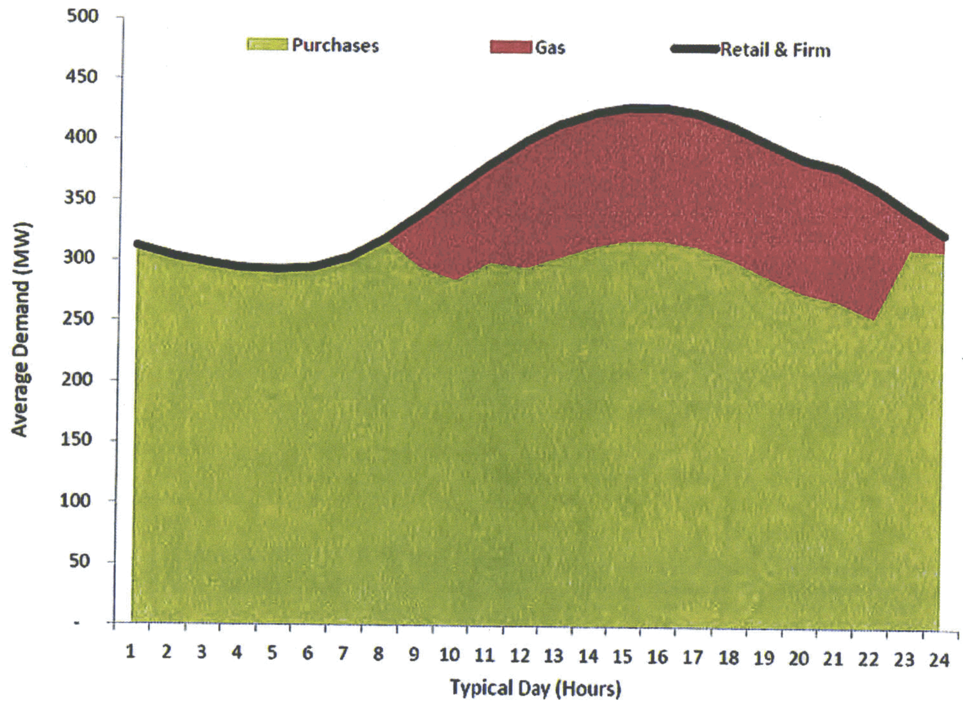
[29] Fischer, Barry and Ben Harak. *9% of solar homes are doing something utilities love. Will others follow?* Opower blog December 1, 2014. *Please see*: https://blog.opower.com/2014/12/solar-homes-utilities-love/.(Downloaded 2016).
[30] *See* Direct Testimony of Bradley Albert at p. 9.
[31] UNS Electric's 2014 Integrated Resource Plan. Arizona Corporation Commission Docket No. E-0000V-13-0070 (April 1, 2014) p. 59. (*See* Chart 12 below).

Chart 12 - 2015 Typical Summer Day Dispatch



Because utilities can't count on it to be available, and because the utility's peak demand occurs well after peak solar production, rooftop solar can play only a limited role in offsetting capacity costs, either for transmission or generation.[32] At best, capacity value would be only a small fraction of nameplate capacity. In fact, some studies find that adding rooftop solar increases costs associated with reserve requirements significantly.[33]

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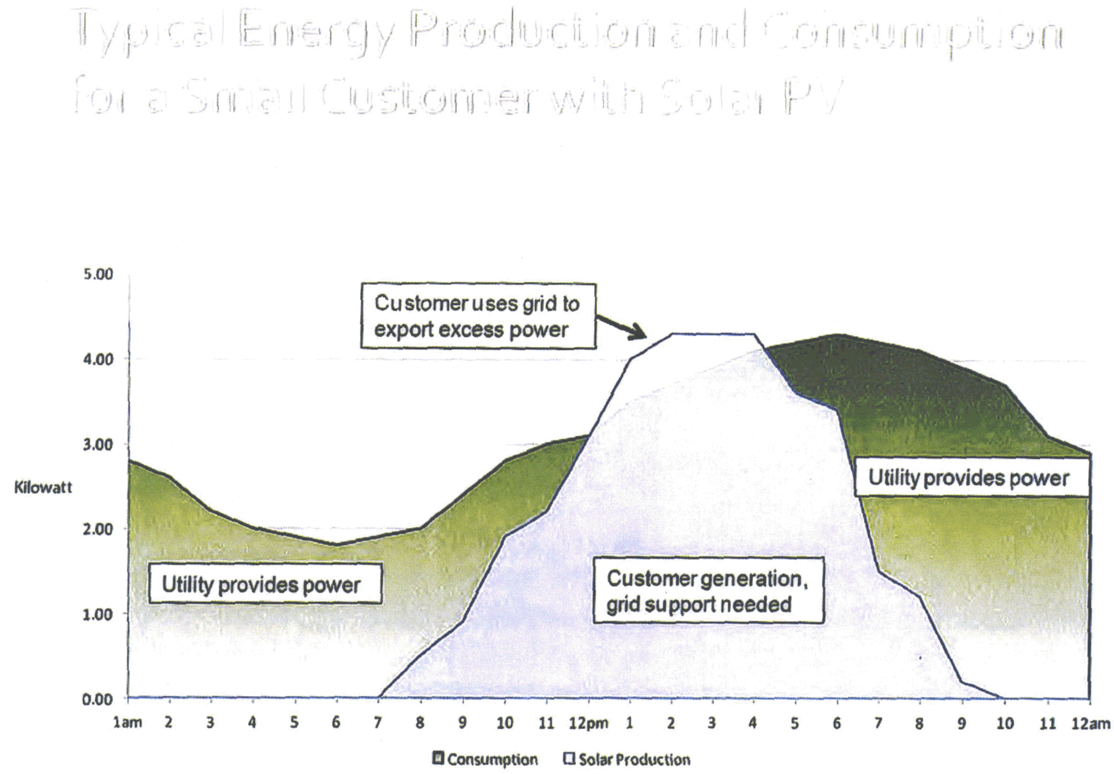
[32] Capacity value can be enhanced by adding battery storage or optimizing the solar installation's orientation to capture the maximum amount of sunlight at peak. Ironically, neither of these actions are routinely undertaken, in large part because net meter pricing fails to provide inappropriate signals to do so.

[33] A study of the Duke Carolina system by Pacific Northwest National Laboratory cited by the Brattle group "found that adding distributed solar capacity equal to 20% of the peak load caused planning reserve requirements to increase by 30% and regulation to increase by 140%, compared to a case without PV capacity added. These increases led to a system cost increase of $1.43 to $9.82 per MWh of PV energy…" *See* Brattle Group Study at 35; and *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas*, Pacific Northwest National Laboratory (March 2014). *Please see:* http://www.duke-energy.com/pdfs/carolinas-photovoltaic-integration-study.pdf.

Another graph, from EPRI, reveals the same pattern on a national level:



Analysts point out that the gap between solar peak production and demand peak is likely to grow as higher penetrations of solar depress demand more and more during solar producing hours—further eroding the capacity value of rooftop solar.

Q. HOW HAVE SOME VOS ANALYSES ATTEMPTED TO HANDLE THE ISSUE OF SOLAR'S INTERMITTENCY?

A. Despite this disjunction between solar production peak and actual peak demand, and the other weather-related uncertainties of solar power, it has become fairly common practice among utility planners and many VOS analysts to calculate an "effective load carrying capacity" (ELCC) percentage based on the capacity of rooftop solar discounted for its intermittency. Typically, ELCC numbers are in the 50%-60% range—but it is acknowledged that the higher the solar penetration, the lower the ELCC is likely to be. Estimates for California have gone as low as 17%. Determining the ELCC adjusted value of rooftop solar is a fact-specific question that, if it is to be used, needs to consider capacity availability resulting from the timing of generation and less than optimal placement of photovoltaics.[34]

Q. WHAT IS YOUR PERSPECTIVE ON THE CAPACITY VALUE OF SOLAR POWER AS A FORMER REGULATOR?

A. While it is true that one can develop probabilistic models for utility planning purposes that are theoretically sound, that is quite different matter than how to price rooftop solar from a regulatory perspective. The regulator needs to determine what is used and useful for providing service to the customer before requiring consumers to pay. In my view, a capacity provider should stand ready to deliver energy when called upon to do so, and if the provider is unable to deliver, then he must assume responsibility for replacing what he is unable to provide, or, alternatively, reimburse the utility for the marginal costs it incurred in remedying his default. Thus, any "capacity" that fails to meet that test is entitled to, at best, minimal compensation, if any, and under no circumstance should it be entitled to payment consistent with its nameplate capacity, unless it meets the test I just articulated. As a regulator, I would apply a very strict scrutiny to the amount of cost recovery for capacity for a resource that is not readily dispatchable, and whose provider assumes no liability for an inability to be dispatched when called upon. The real question is how much benefit of the doubt should we give to an intermittent, non-readily dispatchable resource, whose provider assumes no liability for inability to be dispatched. The question for regulators is how they assess capacity value in light of these factors.

[34] *See* Baker et al, at. 405, who cite study by Lamont (2008).

Q. ARE THERE ANY OTHER LIMITING FACTORS IN EVALUATING THE CAPACITY VALUE OF DISTRIBUTED SOLAR POWER?

A. Yes. The value of capacity is also, of course, driven by whether capacity is required. If, for example, a utility has sufficient capacity[35] to meet all anticipated demand (including reasonable reserves), voluntarily paying for more capacity would raise questions about prudency. Thus, there is no basis to assume, as many VOS authors do, that the installation of new rooftop solar units renders them automatically entitled to capacity payments. Indeed, I know of no other circumstance where any generator would be entitled to such a presumption, without actual examination of the particular circumstances. Even in the context of where the utility has a need for new capacity, economies of scale are important. New plants might be built that could have scale economies and serve multiple purposes, but do so at lower unit costs than small plants, such as rooftop solar, which lack economies of scale. Given the lack of scale economies in rooftop solar, prevailing in a competition would be difficult. Capacity markets are, and ought to be, competitive; thus, even if rooftop solar possessed capacity value, it should have to compete to monetize that value. This is entirely contrary, however, to the way that most VOS authors approach the issue of capacity value. They simply assume that solar installations are entitled to compensation for being there, without having to compete with other possible capacity providers. They simply assume value associated with a deferral of capacity procurement, despite the fact nothing may be deferred at all. Moreover, the value calculation is often made at nameplate capacity levels, as opposed to ELCC. Using nameplate capacity levels serves the purpose of driving up the "value" calculations they make, but does so in a context entirely outside the realities of the capacity market.

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[35] From a regulatory perspective, utility capacity includes both units owned by the utility and units owned by a third party entity with a contractual obligation to provide the utility with capacity. I note this because solar advocates sometimes argue that utilities are opposed to rooftop solar because it competes with the utility's generation. For regulatory purposes, capacity owned by another company, but contractually obligated to the utility to serve capacity requirements, has the same system worth as utility owned generation for purposes of capacity. Ownership has nothing to do with it.

Q. WHAT ABOUT VALUES ASSIGNED TO TRANSMISSION AND DISTRIBUTION CAPACITY?

A. Advocates of a "VOS" approach often assert that real transmission savings are achieved through the deployment of DG. The argument is that by producing energy at the distribution level, less transmission service will be required, thereby reducing or deferring the need for new transmission facilities. It is also, as already noted above, often contended that rooftop solar will reduce congestion costs, and perhaps even provide some ancillary services. All of that is theoretically possible, but certainly not uniformly or even inevitably true.

Of course it is true that, absent any adverse, indirect effect rooftop solar might have on the operations of the high voltage grid (e.g., congestion), rooftop solar does not incur any transmission costs in bringing its energy to market. However, as discussed above, avoiding transmission delivery charges is quite different from asserting that rooftop solar provides actual transmission savings. In fact, it would be incorrect to simply conclude that rooftop solar will achieve transmission savings.

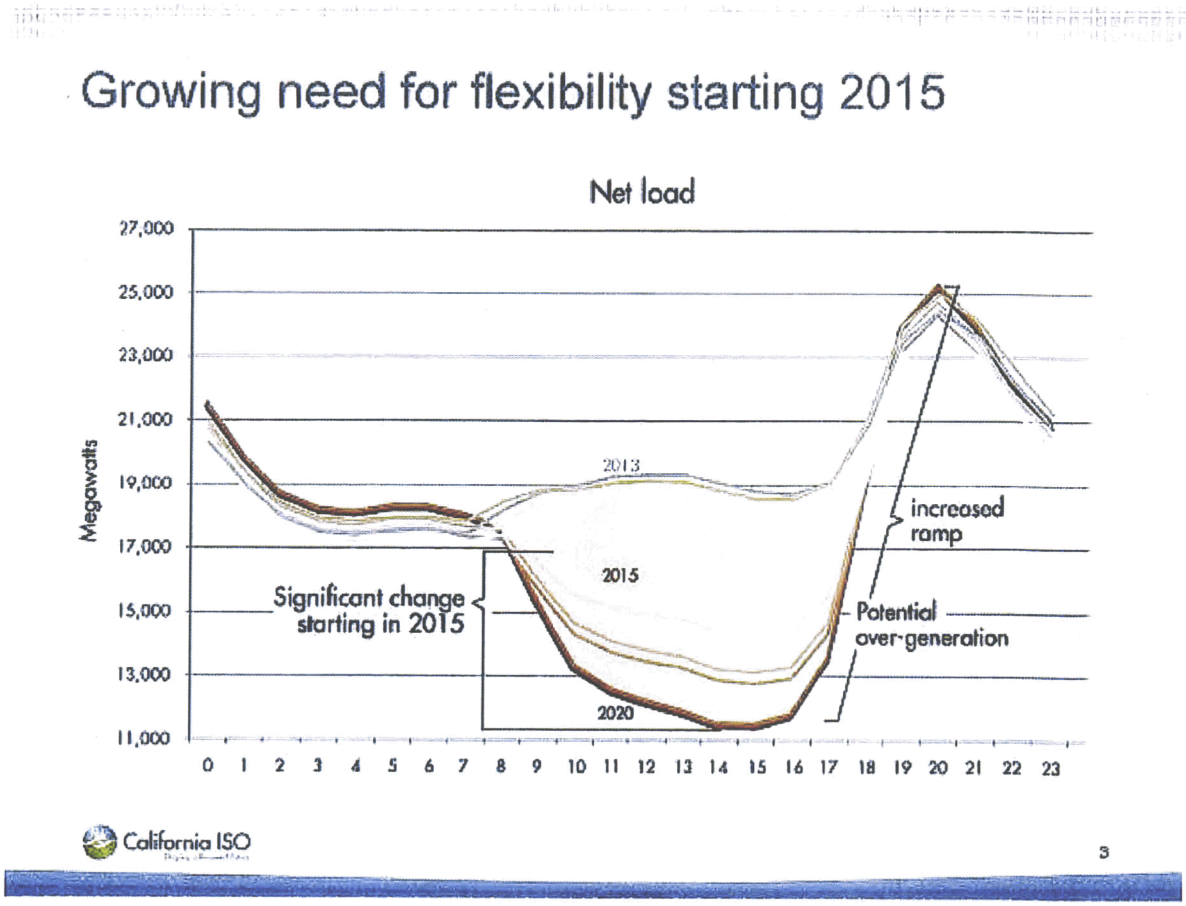
It is possible that there could be transmission savings associated with rooftop solar deployment, but that can only be ascertained on a fact- and location-specific basis. Such savings, as already discussed, would most likely be derived from reducing congestion or providing ancillary service of some kind. It is also theoretically possible, but highly unlikely, that massive deployment of rooftop solar will eliminate (or defer) the need to build new transmission facilities. However, for a variety of reasons, including the complexities of transmission planning, the time horizons involved, the complex interactions of multiple parties, economies of scale in building transmission, and the politics of siting, it is improbable that rooftop solar actually saves any investment in transmission capacity.

The fact is that transmission is built for the bulk power market, sized for the long term, and designed to capture economies of scale. It is built, not based on incremental, year by year, needs, but with a view toward the long term. Since rights of way are generally scarce and hard to obtain, transmission lines are built to maximize scale so that future line siting battles can be avoided or at least deferred. Thus, the addition of rooftop solar, absent a truly massive amount of installation, will almost inevitably have no impact on transmission capacity planning. Indeed, since transmission must be sufficient to serve peak load, the fact that rooftop solar is intermittent, and non-coincident with peak, means that it will have no real impact on transmission capacity. In addition, with new technologies being deployed on the grid, the most common form of transmission expansion relates to technological enhancements, the deployment of which is completely unaffected by rooftop solar.

Indeed, a mere glance at the California ISO duck chart, which shows the need for ramping capacity to make up for the intermittent availability of rooftop solar, is almost a prima facie case for believing that the opposite is true-that rooftop solar may actually cause a need for more transmission to be built.

For anyone not already familiar with California's famous fowl, here is the "duck chart," which shows the dramatic and increasing ramp needed to meet residential demand as the sun sets-a ramp that taxes the resources of the system and may well put significant strains on the transmission system:[36]

[36] *See* Rothleder, Mark. *Long Term Resource Adequacy Summit*. California ISO (February 26, 2013 at slide 3. *Please see:* https://www.caiso.com/Documents/Presentation-Mark_Rothleder_CaliforniaISO.pdf.



It is virtually impossible to demonstrate that rooftop solar will obviate the need for transmission, much less quantify the cost savings associated with this purported benefit. At the same time, the development of this "duck" pattern creates new costs for the grid—it is not easy or free to arrange for large amounts of generation to come on line quickly ("ramping"). Keeping up with the steep ramping curve created as solar power drops off the grid is an additional expense that would need to be included in VOS analysis.

Q. DOES DISTRIBUTED ROOFTOP SOLAR AVOID DISTRIBUTION COSTS?

A. No. It is more likely that rooftop solar will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require adjustments and maintenance. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer. It is impossible, unless perhaps when a rooftop solar host leaves the grid, to envision a circumstance where rooftop solar would effectuate distribution savings.

In a number of states, regulators are working to introduce more market elements in the distribution grid in order to handle the additional costs and complexities (as well as to create efficiency opportunities) related to distributed energy resources. This project itself, of course, represents a significant cost.

Q. IS THERE VALUE ASSOCIATED WITH ROOFTOP SOLAR RELATED TO ANCILLARY SERVICE PROVISION TO THE GRID?

A. It is technically possible that smart inverters could provide ancillary services to help stabilize energy flow on the grid. However, in the absence of a properly designed incentive to provide these services, this is a theoretical possibility, not an actual value. In the meantime, the more intermittent resources on the grid, the more ancillary services are needed to preserve power quality and reliability.[37]

Q. IS THERE A FUEL HEDGE VALUE ASSOCIATED WITH ROOFTOP SOLAR?

A. The theory advanced by some rooftop solar proponents is that because the marginal cost of solar is zero, it serves as a hedge against price volatility. In theory that might make sense. In reality, however, rooftop solar is an intermittent resource that cannot serve as a meaningful hedge unless such zero-cost energy is produced both in sufficient quantities and in a timely manner. Thus, rooftop solar is the equivalent of a risky counter party whose financial position renders him incapable of assuring payment when required. Moreover, the value of a hedge depends on the amount of money the purchaser of the hedge is obliged to pay and the size and probability of the price he/she seeks to

[37] Baker et al., at 404-405.

avoid paying. With a rooftop solar system (or the high-priced "VOS" approach that the rooftop solar industry seeks), the price paid is highly likely to exceed the fuel or energy price against which most utilities would hedge against. In short, the argument ventures into the realm of the absurd. It amounts to: Pay me a fixed price that is higher than the price you want to avoid, in order to avoid price volatility.

Q. WHAT ABOUT THE VALUE OF "MARKET PRICE SUPPRESSION?"

A. Another supposed value attributed to rooftop solar in many VOS studies is that by reducing demand, rooftop solar will suppress the market price for energy. This argument is seriously flawed in more than one way.

In the first place, under retail net metering, the price of rooftop solar is not market-based, or even cost-based. In fact, where there is retail net metering, the rooftop solar price is unreasonably and arbitrarily linked to the full retail price of delivered electricity, as opposed to the level of energy prices, where it should be. While, arguably, the availability of highly-subsidized rooftop solar could have the effect of reducing demand for wholesale energy (although considering the scales involved it seems improbable that the reduction would materially impact wholesale energy prices), there would be no price benefit for consumers since rooftop solar, priced at full retail levels, or at the levels dictated by the inflated claims of many VOS papers, would consume all of the savings and leave little or no benefit for customers.

Setting aside the high price customers are being asked to pay for this "savings," the second problem to flag here has to do with the different market effects of a low-priced competitive resource and a low-priced subsidized resource. If a competitively priced, not heavily subsidized, source of energy caused prices to decline, that would be a good thing, but that is not at all what VOS studies are suggesting will happen with rooftop solar. Rooftop solar is subsidized by tax credits, REC/SREC markets, and by the cross-subsidy inherent in net metering and volumetric rate design. It is hard to find any economic logic to support the notion that markets are well served by using heavily subsidized products, such as rooftop solar, to drive down prices in the competitive marketplace.

To the extent that highly subsidized products compete with unsubsidized products in the marketplace, this distorts the market, rather than strengthens it, making it hard for otherwise competitive energy generators to stay in business. In the long run, this distortion exacerbates the capacity issues that many markets struggle to correct through capacity payments. Thus, if one assumes that rooftop solar somehow suppresses prices in the energy market, this would be highly unfortunate—it could do very serious damage to the power sector. The claimed price suppression "value" is not a value at all.

Q. WHAT ABOUT THE AVAILABILITY AND RELIABILITY OF ROOFTOP SOLAR?

A. Many rooftop solar advocates assert that rooftop solar enhances overall reliability because the units are small and widely distributed, but close to load and not reliant on the high voltage transmission system. It is argued that they are somehow less impacted by disasters and weather disturbances. These claims are highly speculative and, for the reasons I will explain, inaccurate.

It would be a mistake to simply assume that rooftop solar improves reliability. First, it should be noted that the vast majority of outages are distribution (not transmission related), thus the fact that rooftop solar does not use the transmission grid is almost completely irrelevant to the reliability issue. Beyond that, rooftop solar is subject to disaster as much as any other installation. Strong winds, for example, can harm rooftop solar as much as any other facility connected or not connected to the grid. Cloudy conditions can disrupt solar output while not affecting anything else on the grid.

Solar's intermittency makes it unable to assure its availability when called upon to deliver energy. Indeed, it is far more likely that a thermal unit will have to provide reliability to back up a solar unit than the other way around.

It is also important to examine rooftop solar reliability issues in two contexts: that of the individual customer and that of the system as a whole. Solar vendors, as part of their sales pitch, claim that reliability is increased for a customer with a rooftop solar unit because on-site generation provides the possibility of maintaining electric power when the surrounding grid is down. When the sun is shining, this claim is likely to be true. Conversely, without the sun, the claim has no validity.

That argument ignores one highly relevant fact: in a system outage the power inverter, an electronic device or circuitry that converts direct current to alternating current, is automatically switched off to prevent the backflow of live energy onto the system. That is a universal protocol to prevent line workers from encountering live voltage they do not anticipate. Thus, if a rooftop solar unit is functioning properly, when the grid goes down, the rooftop solar customer's inverter will also go down, rendering it useless in an outage. If the inverter is not functioning properly, then the unit may be producing, but will do so at a considerable risk to public safety and to workers trying to restore service. The result, of course, is that the solar panel provides virtually no reliability to anyone.

In fact, when it comes to reliability, it is much more accurate to say the grid provides reliability to rooftop solar than the other way around. Not only does the grid ensure service when the sun is not shining, but in case of an outage, a solar-powered home does not, on its own, have the ability to re-start the home's systems without a boost of energy from the grid. As contrasted with the reliability provided by the grid, there are virtually no reliability benefits for the system from distributed solar, and therefore there is no basis for calculating a payment for such service.

Q. BESIDES LACK OF AVAILABILITY DURING OUTAGES, ARE THERE OTHER ASPECTS OF RELIABILITY THAT ARE RELEVANT FOR CONSIDERATION?

A. Yes. Attributing reliability benefits to an intermittent resource is a stretch. By definition, intermittent resources are supplemental to baseload units. The only possible exceptions to that are, as noted above, where there are individual reliability benefits or where the availability of the unit is coincident with peak demand. Absent those circumstances, and absent storage, it is almost certainly the case that the system provides reliability for rooftop solar, rather than the other way around. That is particularly ironic given that in the context of net metering, rooftop solar hosts do not pay for that service while generating electric energy, and collect payments for distribution service they rely upon rather than provide.

Indeed, from a reliability perspective, net metering and most other VOS formulations are truly perverse, because non-solar customers pay rooftop solar providers for reliability benefits that rooftop solar does not provide them, while rooftop solar customers do not pay for the reliability benefits they actually do receive. From an investment perspective, rooftop solar pricing methods like NEM, which redirects distribution revenues from utilities to rooftop solar providers who offer no distribution services, are detrimental to reliability because they deprive utilities of the revenue needed to maintain high levels of service.

Q. DESCRIBE THE EFFECTS OF DIVERSION OF REVENUES RELATED TO THE NETWORK FROM UTILITIES TO ROOFTOP SOLAR PROVIDERS, WHO OFFER NO NETWORK SERVICES, ON RELIABILITY AND REVENUE REQUIREMENTS FOR PROVISION OF NETWORK SERVICES.

A. For utilities, the diversion of funds leaves them with the Hobson's choice of either delaying maintenance and/or needed investment, foregoing earnings,[38] or seeking a rate increase—in effect, a cross-subsidy from non-rooftop solar users. Over the long term,

[38] Foregoing earnings increases investor perception of risk. That perception will inevitably drive up a utility's cost of capital, so that option will also lead to rates being increased.

that effect could lead to reliability problems associated with inadequate or less reliable network capacity, especially at times of peak demand.

Q. DO YOU SEE VALUE IN "ENVIRONMENTAL SERVICES" RELATED TO CARBON AND OTHER FACTORS?

A. Many VOS studies include one or more values related to environmental impacts (or lack of impact) of rooftop solar. Before delving into the issue of the environmental externalities benefits claimed for rooftop solar, it is important to note that the issue of taking externalities into consideration is a controversial one. It would, of course, take a policy decision by the Commission to look at the claims of environmental values beyond what is currently required by law. That is, of course, the Commission's call I am not, in my testimony, suggesting that the Commission should or should not take externalities, environmental or otherwise, into consideration in reviewing the idea of VOS analysis. If the Commission does decide to consider externalities, however, as a matter of soliciting a full range of information and analysis from interested parties, it might want to leave open the issues of what rooftop solar related externalities the parties might want to address. That way, the parties seeking to provide input to the Commission will face no entry barriers to do so. How the Commission chooses to weigh those comments, of course, is very much the Commission's decision. For purposes of my testimony, however, since I am talking about VOS studies that look at externalities, I will specifically address the issues explored in those studies, and perhaps some others as well, but my testimony is not intended to be an exhaustive list of all affected externalities.

There are many potential issues here. First there is no certainty that rooftop solar reduces carbon emissions. There is, for example, the case of Germany, where a massive switch to solar and wind resulted in an increase in the use of coal, and stalled reductions (and in some years increases) in carbon emissions.[39] While the German experience was also influence by the closing of the country's nuclear plants, the point is that one simply cannot assume that increasing the amount of intermittent renewable generation, including rooftop solar, will, ipso facto, lead to reductions in emissions.

Moreover, the degree to which rooftop solar does reduce carbon is not an easy figure to derive. To correctly ascertain the amount of reductions per dollar spent, one would have to identify what generation and emissions are being avoided by rooftop solar generation. In today's market, the marginal resource is likely to be natural gas—with emissions much less than other resources on the grid, such as coal—resulting in significant consequences for the value of the emissions averted by rooftop solar. To try to ascertain a meaningful number, a VOS researcher would have to do a location (or at least region) specific analysis with substantial granularity. VOS papers typically do not do that; rather they simply make assumptions, the factual basis for which are at best suspect and at worst meaningless.

Second, as in other issues, VOS studies almost never look at the opportunity cost associated with rooftop solar. In specific regard to carbon emissions, VOS studies assume a reduction and try to assess a monetary value for that achievement. What they rarely, or ever do, is look to see if that money is well spent in the context of alternative ways of achieving the same result. As noted earlier in my testimony, rooftop solar is a remarkably expensive way to reduce carbon emissions. Energy efficiency, grid-scale solar, and wind, for example, all reduce more emissions per dollar spent on rooftop solar, and do so without having to prepare VOS studies to make the case for special compensation. Thus, a balanced VOS would discount the claimed value of emissions

[39] *DW.Com*. "German CO2 Emissions Targets at Risk." (November 19, 2015). *Please see:* http://www.dw.com/en/german-co2-emissions-targets-at-risk/a-18862708

reduction to compensate for the opportunity cost of not having chosen the least cost option. Most (if not all) studies fail to do this.

Third, the methodology used to quantify emissions reductions in VOS studies often suffer from serious flaws. There appears to be the potential double counting and paradoxes among the different categories of analysis suggested for the "environmental services" category. For example, IREC suggests a list of values within the "environmental services" category that includes both "utility avoided compliance costs" and "carbon." The "carbon" category suggests that additional value attaches to rooftop solar because it reduces the amount of carbon emissions in the state; on the other hand, the "avoided compliance cost" category suggests that there is value to rooftop solar because it reduces the amount of other renewables in the state. Puzzling through the relationship between these two arguments is like trying to make sense of an Escher print—at first glance, the steps seem to be going up, but at second glance, they are going down, and it is impossible to resolve the contradiction.

Q. HOW DO CAP AND TRADE AND RENEWABLE PORTFOLIO STANDARDS FIT INTO YOUR ANALYSIS?

A. It is also apparent, but ignored in most if not all VOS studies, that in jurisdictions with a renewable portfolio standard or a cap and trade system, additional rooftop solar does not necessarily change the amount of emissions being reduced. Indeed, it could have adverse effects. That is because, cap and trade turns carbon from an externality to a cost that is fully internalized into the cost of service, and set asides or preferential prices to selected technologies (i.e. rooftop solar), actually have the effect of disrupting the ability of the market to find the most efficient way of reaching the emission reduction requirement. In regard to RPS, the cost of compliance with the standards is also internalized into the cost of service, so whatever carbon reductions are attained under RPS are automatically captured and internalized into the cost of service. The rooftop solar set aside in the Arizona (and other states with similar requirements) RPS, however, is a bit of an outlier with perverse results. That is because it mandates that a specified percent of renewable must be dedicated rooftop solar, a resource that is less efficient economically and less efficient in reducing carbon emissions than are other renewable resources. It is remarkable that the authors of VOS studies, for the most part, simply choose to ignore this issue.

Q. WHAT ABOUT RENEWABLE ENERGY CREDITS AND SOLAR RENEWABLE ENERGY CREIDTS?

A. This issue becomes even more complex and problematic in cases in which customers and/or rooftop solar installers are awarded RECs or SRECs for their projects. Clearly, if customers or solar installation companies are selling RECs or SRECs associated with their renewable energy, care should be taken not to count the associated environmental "value" more than once.

Q. WHAT IS THE EFFECT OF THE LONG TERM COST PROJECTIONS FOUND IN VOS STUDIES?

A. It is perverse on both economic and environmental grounds. As noted elsewhere in my testimony, long-term forecasts of fuel and energy prices are notoriously inaccurate and should not be relied on for purposes of pricing long-term contracts[40]. In regard to carbon reduction and other environmental effects, it is impossible to overstate the perversity of setting long-term prices. That is not only because, as regards to rooftop solar, you are giving pricing preference to the least efficient technology for reducing carbon, but for an even more important reason. Environmental standards, particularly market-based approaches such as cap and trade, are formulated in ways that incentivize new and more efficient technology to achieve the desired ecological result. What most

[40] Utilities and many other businesses often rely on such projections for planning purposes, but use the projections solely as indicators of trends, not as is suggested in VOS studies, for establishing the price for long-term contracts.

of the VOS studies propose to do, however, is lock in high prices projected out for 20-25 years for a technology we already know to be inefficient relative to other options, and reduce the opportunities to seize upon options that we can be certain will appear in that time frame that will achieve the desired environmental results at lower cost to consumers. Simply stated, it is very poor policy to lock in long term prices for a technology we know is inefficient and thereby reduce our opportunity to take advantage of new technology that will inevitably appear in the marketplace.

Q. HOW DO YOU ASSESS THE VALUE CLAIMED RELATED TO "SOCIAL SERVICES" (PRIMARILY, ECONOMIC DEVELOPMENT AND JOBS)?

A. In the case of economic impact, benefits are frequently claimed for rooftop solar without regard to costs. Advocates for rooftop solar claim this will give rise to many good solar energy jobs. Maybe that's true, maybe that's not true. We certainly have some reason to doubt this, given that as of 2015, the US produced only about 2% of PV cells and PV modules in the world, while making up 16% of PV installations. (China dominates worldwide solar PV cell and PV module production, with a more than 60% share of the world market).[41] Rooftop solar may have produced more jobs in China than in the U.S. Regardless, if one is to consider the economic development or jobs aspects of rooftop solar, any study of the issue must be balanced and look not only at solar jobs, but also at secondary impacts on the job market. These include job loss caused by the increased electric rates that come with selecting a higher cost technology over a lower cost technology to provide electricity (e.g., rooftop solar instead of utility scale solar or wind). Employment impacts are a two-edged sword when it comes to green energy. The one-sided, myopic view of the jobs issues found in VOS studies are strangely reminiscent of people who argue that we ought not to regulate carbon emissions because

[41] IEA, *Trends 2015 in Solar Photovoltaic Applications.* Report IEA-PVPS T1-27:2015. Available online at http://www.iea-pvps.org/fileadmin/dam/public/report/national/IEA-PVPS - Trends 2015 - MedRes.pdf. See pages 31 and 40.

doing so would lead to job loss in coal mining. That argument is one dimensional and myopic in the same sense that the green jobs argument is one dimensional and myopic.

In fact, recent research modeling on the effects on the Arizona economy of rooftop solar subsidies highlights what is missed with a one-dimensional look at rooftop solar jobs. This study found that subsidies for rooftop solar, over the years, lead to significant job losses and decreased wealth for the state.[42] The central problem is that the money spent on DG reduces the amount available to be spent in other sectors of the economy. Thus, while the model does predict additional jobs associated with rooftop solar installation and other services, "Any benefits emanating from each scenario are at best temporary, only coincident with the timing of the solar installations, and quickly counteracted by their long-run/legacy effects."[43] Over the twenty-year period studied, with results varying depending on the level of penetration of rooftop solar, the model in fact predicts billions of dollars of lost gross state product and thousands of "job years" lost.[44] The effort of the ASU Study to examine both sides of the economic impact of expenditures on distributed solar is unfortunately rare in VOS analyses, which almost never balance predictions of job growth against job costs. The usual VOS jobs argument simply lacks balance and credibility.

Q. ARE THERE ANY SOCIO-ECONOMIC ISSUE THAT ARE NOTABLY IGNORED IN VOS STUDIES?

A. One issue that VOS studies never reference, but which has been studied on several occasions, is that cross-subsidies in rates derived through net metering or inflated value claims by the rooftop solar industry inevitably have a regressive social effect in that they

[42] Evans, Anthony, Tim James, and Lora Mwaniki-Lyman. "The Economic Impact of Distributed Solar in the APS Service Territory, 2016-2035." Report, L. William Seidman Research Institute, W.P. Carey School of Business, Arizona State University, February 16, 2016. (ASU Study). (Attachment ACB-2DR).

[43] ASU Study at i.

[44] A job year is not the same as a job. It is one year of employment

constitute, in the aggregate, a transfer of wealth from less affluent households to more affluent ones.[45] That reflects a very real social cost, but one that VOS authors routinely ignore.

i. Case Studies: How the problems of VOS analysis play out in specific studies

Q. CAN YOU GIVE EXAMPLES OF HOW THE GENERAL AND SPECIFIC ISSUES DESCRIBED ABOVE PLAY OUT IN VOS STUDIES?

A. Yes. In what follows I give, not a complete review of all aspects of the studies mentioned, but a "highlights" (or perhaps more accurately, "lowlights") tour of what I perceive to be the major problems with the VOS analysis illustrated by each study. I review one study in Louisiana, two contrasting Arizona studies, and a recent study of the VOS in Maine.

Q. WHAT, IN YOUR VIEW, IS THE KEY LESSON OF THE LOUISIANA STUDY?

A. It matters a lot what subsidies you count, as demonstrated by the Louisiana study.[46] This study, a rare example of an analysis that finds the costs of rooftop solar to be greater than its benefits, proved controversial, and has remained in "draft" purgatory since it was submitted to the Commission that requested it. Many criticisms of the study have focused on the author, David Dismukes, himself, arguing that his past work for oil companies makes him likely to be biased. (I wonder how many energy consultants in Louisiana have not worked for oil companies).[47] More substantive critiques noted the

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[45] Energy and Environmental Economics, *California Net Energy Metering Ratepayer Impacts Evaluation*. Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 28, 2013); Hernandez, Mari. *Rooftop Solar Adoption in Emerging Residential Markets*. Center for American Progress, May 29, 2014. and Hernandez, Mari, *Solar Power and the People: The Rise of Rooftop Solar Among the Middle Class.* Center for American Progress, October 21, 2013; Staff Report/Open Meeting Memorandum on Arizona Public Service Company – Application for Approval of Net Metering Cost Shift Solution. Arizona Corporation Commission Docket No. E-01345A-13-0248, September 30, 2013.

[46] *See* Dismukes, Davide E. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers.*

[47] Furthermore, it is a leap to assume that the interests of oil companies are opposed to solar electricity (which does not directly compete with oil). In fact, many oil companies have investments in renewables, and even more have an interest in natural gas—which becomes more in demand for electricity generation as a flexible firming resource for intermittent renewables on the system. Oil companies'

inclusion of the State of Louisiana's generous solar tax credits in costs—and, in fact, Dismukes would have found a net benefit for rooftop solar if he had excluded the cost of this state support.

A review of the study points to a few observations. First, Mr. Dismukes was working with severely limited data provided by Louisiana's "dumb" meters. He seems to have made heroic efforts, combining GPS coordinates with weather data, to extrapolate likely levels of rooftop solar energy production at different hours of the day. His methodology seems reasonable to me, but I have not reviewed it in detail.

The study itself contains multiple analyses. In addition to his net benefits/costs analysis, Dismukes analyzes the impact on the contributions to cost of service by NEM customers, finding (as one would expect) that NEM customers contribute far less to the cost of service than they would have done had they not installed rooftop solar and received service under a NEM tariff. This analysis is interesting in that it illustrates the scope of the shift of costs from NEM to standard rate customers. However, it is vulnerable to the criticism that it does not consider any reductions in the overall cost of service resulting from the rooftop solar installations. (APS witness Leland Snook calculated these savings in APS's service territory and concluded that rooftop solar customers reduce energy costs and provide a modest capacity benefit to APS). He goes on to analyze evidence that the transfer here is from lower-income to higher-income households, finding considerable evidence that this is the case.

Focusing on the most-reported finding, that the costs of solar NEM installations are greater than the benefits to ratepayers, I note that in some of his assumptions, Dismukes is relatively generous to rooftop solar. For example, he assumes the price of natural gas

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economic interests, to the extent they are impacted by electricity policy at all, would be to support bringing more intermittent renewables onto the system.

would be constant at \$3.50/MMBtu—a price that today seems high.[48] He also includes capacity value (for generation, transmission, and distribution) in his analysis, despite the intermittency of rooftop solar, using an ELCC factor to calculate avoided generation capacity costs, even though the value of the capacity is limited by the prevalence of excess capacity in area markets. Dismukes is similarly generous in calculating transmission and distribution capacity savings. He assumes benefits in transmission and distribution capacity which, as I argue above, are highly dependent on the particular configuration of the utility system, and of rooftop solar within that system. Finally, though it is not part of his main analysis, he includes a sensitivity analysis which looks at how his findings would change if a \$40 per ton cost of carbon were included (and finds that rooftop solar remains in the red, even with this additional included benefit).

How is it possible, then, that his results are so different from some other studies? Critics of the study quibble about his omission of certain "values" they consider relevant. But the biggest differences seem to be the following:

- Dismukes presents a balanced assessment of the impact of NEM and solar subsidies on jobs and the economy of Louisiana. Thus, he counts the benefits of jobs and economic activity associated with the subsidy—but he also counts the negative economic impact of higher electricity prices. In this, he is absolutely correct. Any analysis of positive job impacts of solar subsidies needs to include the impact on jobs caused by the resulting higher energy costs (and the reduction in state revenues associated with tax rebates, if state government costs and incentives are considered). It would be wonderful news if it were possible to create cost-free jobs and economic growth through government subsidies for any industry (green or not) —but, as economists like to say, "There is no such thing as a free lunch." This is not to say industry subsidies are never helpful or a good

[48] Dismukes, at 112.

idea—but industrial economic policy is a complex topic, and any presentation that suggests that benefits come without costs is deeply wrong.

- In addition, Dismukes includes a big ticket cost that many other studies omit—the cost of state tax incentives (in addition to the NEM subsidy) provided to customers who invest in rooftop solar (Louisiana offers a tax rebate of up to $12,500 per system).[49] This tax subsidy has a huge impact on his analysis, accounting for roughly 70% of the costs of historical solar installations he identifies.[50] (It's worth noting here that he does not include costs associated with the federal solar tax incentive.) Although it has been correctly pointed out that these state costs are not within the jurisdiction of a utility commission, this is a perfectly legitimate cost to identify. Just like jobs (which are also outside of a utility commission's jurisdiction) how tax incentives should impact decision-making depends on the priorities of the Commission, recognizing that a decision to end net energy metering may not eliminate these costs.

Q. HOW DO YOU INTERPRET THE VERY DIFFERENT RESULTS OF THE TWO STUDIES OF VOS IN ARIZONA ITSELF?

A. Two roughly simultaneous studies of the "VOS" in Arizona beautifully demonstrate how easy it is to do a "value analysis," using many of the same assumptions, and come to radically different conclusions. The SAIC Report analysis, published in May 2013[51], estimates a rather small 2025 VOS to the APS system of 3.56 cents/kWh (expressed in 2013 dollars). A study by Thomas Beach and Patrick McGuire of Crossborder Energy, also published in May 2013, criticizes the SAIC Report study, offering instead an estimate of "levelized benefits" over twenty years (it is not clear to me exactly which

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[49] *Id.* at 128.
[50] *Id.* at 135.
[51] SAIC, 2013 Updated Solar PV Value Report of Arizona Public Service (May 10, 2013). *(SAIC Report). Please see: https://azenergyfuture.files.wordpress.com/2013/04/2013_updated_solar_pv_value_report.pdf*

twenty years, but I think the analysis may be from 2014-2034) of 21.5-23.7 cents/kWh-more than six times what SAIC Report found.[52] In part, this can be traced to the inclusion by Crossborder Arizona Study of the category of "avoided renewables"—not considered by SAIC Report. But this accounts for only 4.5 cents of the difference. The rest can be traced mostly to differences in estimates of generation capacity and transmission savings, and to some extent to difference in energy costs. What is happening here? Below, I review a few key issues of conflict between the two analyses.

"Snapshot" vs. "levelized cost" analysis

One area of apparent disagreement is really a question of data presentation, but it is a difference that makes clear comparisons between the two studies difficult. SAIC Report presents "snapshots" of the VOS in three different years: 2015, 2020, 2025—capturing how this value changes as natural gas prices are assumed to rise, along with the price of carbon allowances, and integrating different capacity savings values depending on whether solar capacity is judged to be adequate to postpone capacity additions in the given year. Crossborder Arizona Study prefers the (to me, rather confusing) "levelized" analysis, over the years from approximately 2014-2034 (I don't see the exact dates identified anywhere in the text, however). For this reason, it is difficult to know what comparisons between the exact numbers of the Crossborder Arizona Study and the SAIC Report mean-though the best comparison may be between SAIC Report's 2025 numbers (approximately the midpoint of Crossborder's range of years) and Crossborder's "levelized" number.

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[52] Beach, Thomas R., and Patrick G. McGuire. *The Benefits and Costs of Solar Distribution Generation for Arizona Public Service*. Crossborder Energy Consulting (May 8, 2013). (*Crossborder Arizona Study*) *Please see*: http://www.solarpowerdemocracy.org/wp-content/uploads/2014/03/Crossborder_AZ_2013.pdf

Highly technical methodology debates

There is a significant difference in the estimates of avoided energy costs that is difficult to understand, even once you get beyond the differences of "levelized" vs. "snapshot" analysis. SAIC Report's "snapshot" of solar PV value in 2025 estimates avoided variable costs (including fuel and carbon charges) of only 5.93 Cents/kWh. Crossborder Arizona Study sticks with its "levelized analysis," so it does not present a number that can be exactly compared—but its weighted annual 20 year levelized cost figure for its base case is 7.1 cents.

It is impossible to tell, based on the discussion available in the two papers, what the source of the discrepancy is. Assumptions (generous, in hindsight) about the rising cost of natural gas seem to be the same. Both studies assume (plausibly) that the marginal generation being displaced by rooftop solar will be natural gas. Crossborder Arizona Study actually assumes a slightly lower carbon allowance cost than the SAIC Report, so that can't be the reason for Crossborder's higher numbers for the cost of the energy likely to offset by rooftop solar power. Crossborder Arizona Study suggests that an analysis of implied heat rates points to unrealistic assumptions on the part of the SAIC Report about how efficient natural gas plants will be in the future.[53] Further technical discussion would be needed to clarify this point, identify whether it is the source of the discrepancy; and determine if the heat rate assumptions in the model used by the SAIC Report are reasonable. For now, it serves nicely to illustrate the complexity of value analysis, and how easy it is to come up with significantly different values, even when working with similar assumptions.[54]

[53] Crossborder Arizona Study at 8.

[54] The differences in methodology between SAIC and Crossborder, and trying to ascertain which report is more accurate is a perfect example of why relying on "value" analysis is so subjective and easy to bias. Why one would choose to use it, and get into an esoteric methodological debate, when market data and/or cost accounting is readily available and quite transparent, is inexplicable unless proponents of "value" analyses were dissatisfied with the results of cost accounting and/or the market. That constitutes good reason to approach VOS studies very cautiously, with eyes wide open for built in bias.

Capacity and peak

The SAIC Report correctly understands the relationship between capacity and peak load. Capacity needs are determined by peak load, not average load. Given that, as the SAIC Report says, "{t]he APS system peak is somewhat unique, in that it extends past sunset due to the impact from the desert heat," there is what the SAIC Report describes as a "lower coincidence with solar PV production than otherwise would be expected."[55] I would say that is putting it mildly. To the extent that peak occurs after sunset, there is zero coincidence with solar PV production. It mystifies me how solar can be considered to have any meaningful capacity impact in this circumstance; however, the SAIC Report merely "discounts" solar's capacity by about 50% and goes on to consider its impact on the need for major projects. The SAIC Report's valuation of rooftop solar's capacity value is generous.

Capacity

The topic of capacity is where the studies diverge the most. Here there is sharp contrast between the SAIC Report's fact based approach and what can only be described as speculative hand-waving in the Crossborder Arizona Study.

The SAIC Report takes the generating resource mix as of 2012 as a given, and asks what capacity additions will be needed, and whether and when additional rooftop solar might allow capacity investments to be deferred. The SAIC Report notes that APS's capacity needs are fully met until 2017, and finds only limited prospects for deferral of investment after that time.

Crossborder does not disagree that no new capacity is needed before 2017-but it claims credit for existing solar for "contributing to" preventing the need for new capacity up to

[55] SAIC Report at 2-18.

that date. It does not present any evidence that without solar, additional investment would have been needed, but goes ahead and "credits" solar "installed before 2017" with "greater value."[56] This is all poorly defined and explained. How much value is being attributed here? Why are they talking about solar panels installed before 2012 at all, when this report seemed to be about the VOS installed in 2014? If capacity additions to 2017 are deferred based on 2012 capacity by itself, why should rooftop solar added between 2012 and 2017 share the "credit" for this, as Crossborder suggests it should?

One or two paragraphs of speculation follow about possible hedging value if there are sudden losses of capacity (rooftop solar is only a "hedge" against unexpected costs if committing ahead of time to incur the highest costs possible reduces anxiety), and whether peak demand might shift into higher-solar hours—but it is all summarized in a table (table 4 on page 10 of the Crossborder study) which assumes that every unit of solar effective load-carrying capacity offsets an actual investment in capacity, without regard to whether additional capacity is needed in the system or not, or whether the limited additional peak capacity offered by solar is enough to make building a new power plant unnecessary.

There is no coherent argument here. The analysis does not bear comparison with the SAIC Report's careful fact-based analysis of actual planned capacity needs in the system and how solar might contribute.

Avoided Renewables Cost

I discuss above the flaws with valuing this category of benefits, including that it is so often combined with "values" attributed to "avoided emissions," even though rooftop solar is an extremely inefficient way to pursue emissions reductions. In the case of Arizona, although the Crossborder study claims benefits here, the fact that APS already

[56] Crossborder Arizona Report at 9.

had plenty of renewables to meet it state requirement means that the benefits of the additional renewables, from the point of view of meeting requirements, are zero

Q. IS IT RELEVANT, AS THE CROSSBORDER STUDY SUGGESTS, THAT "IT IS CUSTOMERS WHO MAKE INVESTMENTS IN DG RESOURCES?"[57]

A. Not in terms of the value provided to the utility. Customers (and, especially, rooftop solar installation companies) who make investments in rooftop solar are not making a free contribution of capital to the system. They are making a calculated investment, based on their own assumptions about utility rate policy, that the utility will more than compensate them for the full value of the investment. So far, they have been right about this in all cases I am aware of. In effect, what is happening is that customers are making investments on the utility's behalf, over which it has no oversight or control, but the cost of which the utility is obliged to fully repay, with interest (plus a healthy profit margin to the rooftop solar company).

Q. WHAT IN YOUR VIEW IS THE KEY PROBLEM ILLUSTRATED BY THE MAINE STUDY?

A. The Maine study illustrates the crucial importance of getting marginal energy right. Among the studies I examine here, the Maine study takes the prize for the highest identified "VOS," with a "levelized" value of 33.7 cents per kWh over the 25 years analyzed.[58] It also, in my view, takes the prize for the most blatant and inexcusable distortion.

Avoided Environmental Costs

This category is much higher in the Maine study than in many other studies (a levelized value of 9.6 cents per kWh), and rewards closer examination. The Maine study gets a

[57] Crossborder Arizona Study at 13.
[58] *See* Maine Distributed Solar Valuation Study.

significant amount of this value from the calculation of avoided costs related to sulfur dioxide ($SO2$) and nitrous oxide emissions (NOx), which can have significant and costly health impacts. The Maine study is not the only one that includes costs related to SO2 and NOx emissions, but, compared to other studies examined here, it finds a much greater effect—surprisingly large, assuming rooftop solar generally replaces natural gas generation, since natural gas generation has very low emissions of these pollutants. The big culprit in SO2 and NOx emissions is coal-fired generation.

So is the marginal resource in Maine that is being displaced coal generation? Analysis elsewhere in the Maine study would suggest not—avoided energy cost calculations are tied to natural gas futures and price forecasts. However, if you read the appendix (to its credit, unlike many other VOS reports, which are not as thorough in documenting their methodology, the Maine report clearly documents its dubious analytical choices—though the reader must be diligent to find the necessary information), the authors note that the AVERT data used to calculate emissions "includes New York, which is not part of the ISO-NE control area."[59] The appendix goes on to clarify that if the authors had in fact limited the analysis to "FTA rates"—emissions rates for units fueled with oil and natural gas (closer to what they assume is being displaced in their marginal cost analysis) emissions rates would have been radically lower—the appendix goes on to acknowledge that "If the FTA rates were used rather than the AVERT results assumed for this study, the displaced emissions and the net social costs calculated below would be reduced to 8% and 20% of the values calculated here for SO2 and NOx, respectively."[60] What this boils down to, in my opinion, is an admission that the "value" attributed to SO2 and NOx emission reduction is a complete fiction, based on a calculation that rooftop solar in Maine would somehow reduce coal plant emissions in New York. This is ridiculous. Coal is at all times unlikely to be used as a marginal

[59] *Id.* at 83
[60] *Id.* at 84.

resource—and these coal plants are not even part of the same dispatch system as Maine! While it is to their credit that the authors so clearly explain the problem in the appendix, why the authors use this number as if it means something in the main body of the report is beyond me. The tone of the report suggests a sober, earnest, scholarly analytical effort—but this shameless distortion makes me think that what is really going on is an attempt to use analytical tricks to inflate the VOS in whatever way is possible.[61]

Taking this egregious problem together with other issues, Maine study's 33.7 cent "levelized value" is extremely doubtful. "Social cost" analysis in the Maine study adds up to 9.6 cents of the "levelized" 33.7 cent/kWh value—a significant percentage of the value that is found. Another 10.3 cents of "value" are attributed to categories which, as I argue above, should not be considered at all in "value" analysis—market price response (that is, buyer side market power that creates long-term capacity problems) and avoided fuel price uncertainty (in this analysis, the uncertainty that seems to be avoided is lower natural gas costs). The avoided energy cost of 8.1 cents per kWh is tied to what it is already clear are erroneous forecasts of ever increasing natural gas prices. And the avoided generation capacity costs (5.6 cents/kWh) do not reflect that this is intermittent and off peak capacity, and therefore has negligible, if any, impact, on capacity needs—hardly savings the utility can take to the bank. The staggering Maine avoided cost numbers just do not stand up to scrutiny.

[61] I believe the same problem impacts estimates of avoided CO_2 emissions—once again, the report relies here on annual avoided emissions calculated from AVERT—which includes coal plants, whose CO_2 emissions are significantly higher than natural gas plants.

V. POLICY IMPLICATIONS OF PROBLEMS WITH VOS ANALYSIS

Q. YOU HAVE RAISED A NUMBER OF CONCERNS ABOUT VOS ANALYSIS, AND GIVEN EXAMPLES OF SEVERAL ANALYSES THAT ALL COME TO WIDELY DIFFERENT (BUT DOUBTFUL) FIGURES FOR THE VOS. WHAT ARE THE POLICY IMPLICATIONS OF DOING VOS ANALYSIS WITH THESE LIMITATIONS?

A. I see several significant policy implications here:

First, VOS analysis overlooks how certain methods of rewarding "value" disincentivize efficiency and innovation, and it overlooks opportunity cost of privileging dumb solar over smarter solar.

The VOS studies largely ignore the issue of how rate design and pricing affect the long term viability of rooftop solar as an energy resource. They focus almost exclusively on establishing a specified value for purposes of setting prices today. Given that these studies are called "Value of Solar," that is a remarkable omission. This is an important point. It's a point that was really made in the MIT study.[62] Prices for solar arrangements should encourage innovation by incentivizing storage, incentivizing methods of capturing system benefits such as encouraging western as opposed to southern exposure to make it more coincident with peak, or incentivizing the use of smart invertors, among other options. But if instead you simply subsidize or come up with an above market price[63] for the most primitive use of the technology, you do a positive harm to the future of solar. You're not incentivizing increases in productivity. In fact, you incentivize exactly the opposite.

Second, VOS analysis is often used to justify incentives that seem to be distorting the market

[62] *The Future of Solar Energy*. MIT. 2015. (MIT Study) *Please see*: https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

[63] The Louisiana study, of course, does not try to artificially raise the price of rooftop solar, but almost all of the others do so, Nonetheless, that study also suffers from the flaw of considering how prices and rate design could incentivize a more prominent role for rooftop solar.

What's really interesting is that VOS analysis often overlooks (and I've never seen this in any study) the fact that the cost of solar panels have declined rapidly in the past few years. That's a good thing. But as pointed out by the Lawrence Berkeley Lab, installation costs curiously remain high.[64] In fact, of the major economies in the world, with the exception of France, the United States has the highest installation costs of solar anywhere in the world.[65] Why? One possibility is that because net metering sets such an arbitrarily high price, solar vendors and lessors don't need to compete against other resources in the energy market and face no pressure to pass on declining costs to customers. In fact, they pocket those costs. Without any impetus to pass savings onto customers, rooftop solar vendors and lessors derive almost all of the benefits associated with declining panel costs.[66]

Not a single VOS study looks at the costs of devising subsidies and cross subsidies to insulate rooftop solar vendors/lessors from the ordinary pressures of the market. Stated a bit differently, they never raise the seminal question of whether rooftop solar, and consumers in general, would do better in the long run by competing in the long run, as opposed to being priced at the artificial levels derived from highly subjective VOS studies, or the equally artificially high rate inherent in net metering. The VOS studies blithely ignore the fact that there is a functioning marketplace for energy (or its functional equivalent through cost-based regulation, and create a kind of fantasy world where neither exists. The VOS studies fail to even acknowledge markets and regulation

[64] Barbose, Galen and Naim Darghouth. *Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States.* Lawrence Berkeley National Laboratory (August 2015). *Please see*: http://energy.gov/sites/prod/files/2015/08/f25/LBNL%20Tracking%20the%20Sun%20August%202015.pdf.

[65] *Id.* at 23.

[66] This theory is supported by the most recent 10K filing by the nation's largest rooftop solar provider, Solar City, in which they state: "We compete mainly with the retail electricity rate charged by the utilities in the markets we serve,.." In other words, they make no effort to be price competitive with other energy sources, but, rather, with the much higher full cost of delivered energy. Thus, the full and substantial differential between the cost of energy alone and the full delivered cost of energy is left for the rooftop solar vendors to capture for themselves.

as benchmarks to assess the reasonableness of the "value" figure derived from the studies.

Third, VOS analysis neglects other renewable resources, market realities, and the future of solar itself

If you look at the major renewable resources—wind, large scale solar, distributed solar—where you have renewable portfolio standards, rooftop solar almost always comes out at the bottom in terms of efficiency in reducing carbon. And yet we're paying the highest price for the least efficient product. Why? What justifies this discrepancy? For the purposes of understanding VOS, we need to look at this issue and determine how it affects the VOS. This inefficiency detracts from the value of distributed solar, and needs to be reflected in any analysis of the value. It is noteworthy that most, if not all, VOS studies simply do not address why other, more efficient forms of renewable energy should be treated differently, for pricing purposes, than rooftop solar. They do not even suggest that perhaps the price of grid-scale solar and wind might be used as a benchmark to assess the reasonableness of the value figure they derive. They also fail to address the fact that artificially high prices for a less efficient resource will inevitably lead to a reallocation of capital toward the less efficient resource, a development with adverse consequences. Significantly, VOS studies simply do not even consider what their valuation, and the pricing that follows from it, does to the future of solar; whether it would incentivize or disincentivize productivity gains, technological innovations, or enable rooftop solar to be more responsive to the needs of the overall system. These are very serious failures in VOS studies and substantially reduces, if not entirely eliminates, their contribution to the debate over how to price rooftop solar.

VI. RECOMMENDATIONS

Q. SO WHAT DO YOU RECOMMEND?

A. A first step would be to get very clear about a number of things that VOS is not:

VOS is not the same as what solar costs or how it ought to be priced

Appropriate pricing for generation should be based on the competitive market, or, absent that, cost based regulation. VOS-based pricing is neither of these, and, for the reasons I have noted, it is simply an artificial, largely arbitrary and meaningless construct. Calling for VOS studies seems premised on the assumption that neither competition nor cost-based regulation will capture all of the values associated with rooftop solar. That may or may not be true. But regardless, the same may or may not be true about every other resource, so why single out rooftop solar, the least efficient of our commonly used renewable energy resources, for special consideration? Absent a market or cost basis, there's no intrinsic assessment of whether rooftop solar is the most cost-effective way of providing a given value. If we paid for everything that way, things would get very expensive (think of what the value of the grid would be, subjected to a similar analysis.)

Second, VOS is not a good tool for environmental policy.

A key element in value of solar analyses comes from factoring in externalities, such as carbon emissions. It may be appropriate to recognize these as "values," in a value of solar analysis, but it is important to be clear that this may not appropriately translate into pricing. Reflecting such values in pricing is a policy decision, not an administrative decision.

Third, inflating the VOS number is not in the long-term interests of the development of solar energy or of customers, solar and non-solar alike.

VOS analyses tend to focus on preserving, and perhaps even enhancing, cross subsidies inherent in pricing such as net metering, and not on increasing productivity and efficiency in ways that will incentivize solar to be even more competitive. Shielding the rooftop solar industry from cost pressure, however, does not translate into increased deployment or productivity of rooftop solar, nor into customer benefits. Often, it simply translates into increased rooftop solar industry profits. When we pay for something without market competition and/or cost based regulation, we aren't giving the technology incentives to maximize value, as discussed above, even by a simple measure such as ensuring solar panels are facing the right way. We are certainly not giving incentives to pursue more ambitious efficiency maximizing efforts, such as incorporating battery storage, or leveraging the potential of smart inverters associated with rooftop solar installations to help regulate power flow.[67]

Fourth, VOS is NOT a justification for backdooring things that are properly public policy issues—we need to think about who has responsibility/authority for internalizing externalities, and where that discussion/decision should take place.

I talked earlier about values related to environmental services. Often, VOS studies approach this issue as a merely technical discussion of the health and environmental impacts of emissions. However, there are important policy issues at stake here that should be consciously considered, not assumed to be simple questions of technical analysis.

For example, the issue of how best to incorporate the cost of carbon emissions into calculations of the VOS is complex and involves many judgments calls. It's true that if you're anticipating that carbon is going to be regulated and you want a hedge against that risk, there's a logic to taking appropriate action. The problem is that there's also a

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[67] Potential marketization of services like those provided by smart inverters was discussed in a seminar presentation by Michael Caramanis on the topic, "Extending Locational Marginal Cost Pricing to Retail Electricity Markets and Distributed Energy Resources," seminar presented at Harvard University, September 21, 2015. Slides available at http://www.hks.harvard.edu/m-rcbg/cepr/CaramanisHarvardSept21%202015.pdf.

huge risk associated with guessing wrong. If you pick a technology that turns out not to be the most cost effective, or one that turns out to stick the state with a lot of costs as it develops its implementation plans, utility customers can experience significant consequences. That point was driven home in the EPA's proposed Clean Power Plan rules, recently stayed by the U.S. Supreme Court. In the originally proposed rules, rooftop solar was accorded basic building block status for compliance, but in the revised, final rules, that status was taken away. Thus, while rooftop solar could still be used for compliance purposes, it no longer carried with it the imprimatur of a basic building block. Hence its value for complying with emissions regulation was reduced. No VOS study even recognizes the risk that heavy investment in rooftop solar to reduce carbon emissions may end up being a costly mistake as a strategy to reach carbon goals. How much reliance can be placed on a study that fails to even acknowledge that risk, or for that matter, as the German experience has demonstrated, that rooftop solar might not even reduce carbon emissions at all? Indeed, the claims found in most VOS studies that rooftop solar is a hedge against future environmental regulation, may, in fact, turn out not to be a hedge at all, but rather a very costly leap of faith, a risk most VOS authors either overlook or choose to ignore.

Q. SO CAN/SHOULD VOS ANALYSIS BE USED?

A. VOS studies add very little value to the debate over rate setting. While they may add something to the debate in regard to specific issues that they examine, taken as a whole, VOS studies that simply add up long-term projected "benefits" without any market context are not worth the paper they are written on. They are too subjective, too arbitrary, too biased, too methodologically suspect, and too disconnected from the realities of costs and markets to be of much use in establishing principles for pricing rooftop solar.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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Ashley Brown is an attorney. He is the Executive Director of the Harvard Electricity Policy Group at Harvard University's John F. Kennedy School of Government. It is a leading "think tank" on matters related to electricity restructuring, regulation, and market formation. He has been an instructor in Harvard's Executive program on "Infrastructure in a Market Economy," at the World Bank Regulatory Training Program at the University of Florida, and at the European University's Florence School of Regulation. Mr. Brown has also served as an arbitrator in matters relating to the evolution of competition in infrastructure industries.

Before his current activities, Ashley Brown served as Commissioner of the Public Utilities Commission of Ohio, appointed twice by Governor Richard F. Celeste, first for a term from April 1983 to April 1988 and for a second term from April 1988 to April 1993. As Commissioner, he was of five members responsible for the regulation of the state's electricity, telecommunications, surface transport, water and sanitation, and natural gas sectors.

Prior to his appointment to the Commission, Mr. Brown was Coordinator and Counsel of the Montgomery County, Ohio, Fair Housing Center. From 1979-1981 he was Managing Attorney for the Legal Aid Society of Dayton, Inc. From 1977 to 1979 he was Legal Advisor of the Miami Valley Regional Planning Commission in Dayton. While practicing law, he specialized in litigation in federal and state courts, as well as before administrative bodies. He has served as an expert witness in litigation in the courts and administrative agencies In addition, Mr. Brown has extensive teaching experience in public schools and universities.

EDUCATIONAL BACKGROUND	1968	B.S.	Bowling Green State University, Bowling Green, Ohio
	1971	M.A.	University of Cincinnati, Cincinnati, Ohio
	1977	J.D.	University of Dayton School of Law, Dayton, Ohio
			Doctoral Studies (all but dissertation) New York University, New York, New York
	1967		Attended Universidade do Parana; Curitiba, Parana, Brazil as an exchange student

FAMILY	Wife	Edith M. Netter
	Daughter	Sara Mariasha Brown-Worsham
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CURRENT AFFILIATIONS

Member, Editorial Advisory Board of *The Electricity Journal*

Member, Editorial Board, *International Journal of Regulation and Governance*

Member, Board of Directors, e-Curve

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Member, Policy Committee, David Rockefeller for Latin American Studies, Harvard University

Member, Brazilian Studies Committee, David Rockefeller Center for Latin American Studies, Harvard University

Member, Advisory Board of Development Gateway Site, The World Bank

Frequent speaker and lecturer on regulatory, infrastructure, and energy policy matters in North and South America, Europe, Africa and Asia.

PREVIOUS AFFILIATIONS

Member, Board of Directors, Entegra Power

Chairman, Town of Belmont Municipal Light Advisory Board

Member, Board of Directors, Oglethorpe Power Corporation, Tucker, GA

Member, Editorial Advisory Board of *Electric Light and Power*

Vice-Chair, American Bar Association Committee on Energy, Section of Administrative Law and Regulatory Practice

Chair, American Bar Association Annual Conference on Electricity Law

Member, The Keystone Center Energy Advisory Committee

Member, National Association of Regulatory Utility Commissioners

Member, Executive Committee, National Association of Regulatory Utility Commissioners

Chair, Committee on Electricity, National Association of Regulatory Utility Commissioners

Chair, Subcommittee on Strategic Issues, National Association of Regulatory Utility Commissioners

Member, Great Lakes Conference of Public Utilities Commissioners

Member, Great Lakes Conference of Public Utilities Commissioners Executive Committee

Member, Mid-America Regulatory Conference

Member, Board of Directors, The National Regulatory Research Institute

Member, Advisory Council to the Board of Directors of the Electric Power Research Institute

Member, U.S. EPA Acid Rain Advisory Committee

Chair, Planning Section, National Governors' Association Task Force on Electric Transmission

Member, the Keystone Center Dialogue on Emissions Trading

Member, the Keystone Center Project on the Public Utility Holding Company Act of 1935

Member, The Keystone Center Project on State/Federal Regulatory Jurisdictional Issues Affecting Electricity Markets

Member, Policy Steering Group, The Keystone Center Project on Electricity Transmission

Member, Advisory Council of the Board of Directors of Nuclear Electric Insurance Limited

Member, Advisory Council of the Consumer Energy Council of America Project on Electricity

Member, Advisory Committee of the Consumer Energy Council of America Air Pollution Emissions Trading Project

Member, National Task Force on Low Income Energy Utilization and Conservation

Member, Board of Directors, Center for Clean Air Policy

Member, National Blue Ribbon Task Force on Allocating the Cost of New Transmission

Of Counsel, Dewey & LeBoeuf

Of Counsel, Greenberg Tauris

INTERNATIONAL EXPERIENCE

Member, Board of Director, Entegra Power Group

Member, U.S. Delegation of State Government Officials in the Center for Clean Air Policy/ German Marshall Fund Sponsored Exchange on Clean Air Issues to Germany, 1989

Member, U.S. Delegation to International Electric Research Exchange (IERE), Rio de Janeiro, Brazil, 1991

Consultant, Hungarian Ministry of Industry and Trade on Gas and Electric Regulatory policy, 1991-1992

Advisor to Ministry of Trade and Industry on Writing New Laws Governing Electricity, Natural Gas, and Regulation

Consultant, SNE, Costa Rican Regulatory Agency, on Transmission Access Issues, 1992

Advisor on Development of Independent Power Producers and Transmission Access

Consultant, World Bank Mission to Hungary Investigating the Financing of New Power Plants for MVM (Hungarian Electric Co.), 1992

Preparation of Background Materials in Preparation of a World Bank loan to the Hungarian Power Sector

Member, U.S. Delegation, in Conjunction with the U.S. Department of Energy, to the Argentina and United States Natural Gas and Electricity Regulatory Meetings, 1992

Consultant, ENARGAS, the Argentine gas regulatory agency, 1992
Providing Training for ENARGAS Commissioners and Staff

Consultant, USAID India Private Power Initiative Program on the Introduction of Private Generation and Competition into the Public Sector, 1993
Preparation of a Report on Introducing and Promoting Private Investment in the Indian Power Sector

Instructor, Regulatory Training Program of the National Regulatory Research Institute at Ohio State University and the Institute of Public Utilities at Michigan State University, Buenos Aires, Argentina, 1993
Providing Training to Commissioners and Staff of ENARGAS

Consultant, The Province of Salta, Argentina on infrastructure regulation, 1996
Providing Training to Commissioners and Staff of the Regulatory Agency of the Province of Salta

Consultant, USAID, Philippines Electric Sector Restructuring, 1994
Preparation of Analysis and Report on Restructuring the Philippine Power Sector Including the Attraction of Private Capital in Generation, and Introduction of Competition

Consultant, USAID, Russian Electric Sector Restructuring, 1994
Preparation of Analysis and Report on Restructuring the Russian Power Sector Including the Attraction of Private Capital in Generation, and Introduction of Competition

Participant, Harvard University's East Asian Electricity Restructuring Forum, 1994-1995
Delivering a Series of Lectures in China, Indonesia, and Thailand on Reforming the Power Sector

Consultant, Government of Ukraine on Electricity regulatory policy and industry restructuring, 1994-1995
Advisor to the National Energy Regulatory Commission on the Structure, Processes and Substance of Electricity Regulation

Consultant, Government of Brazil on Electric Sector Restructuring, 1995-1996
Adviser to the Ministry of Mines and Energy on Various Issues Related to Privatization and Introduction of Competition in the Power Sector

Consultant, Energy Regulatory Board of Zambia, 1997- 2001
Advisor to the Energy Regulatory Board on the Structure, Processes and Substance of Electricity Regulation

Member, Brazil-U.S. Energy Summit, 1995-1996
Preparation of a Report and Lecture on the Options for the Regulation of a Restructured Brazilian Power Sector

Consultant, Nam Power, the electric utility in Namibia, 1998-1999
Advisor on Development of Independent Power Project and on Restructuring of the Electric Distribution Sector

Consultant, Government of Indonesia on electricity regulation, 1999
Training Government and Industry Personnel on Electricity Regulation

Consultant, Government of Mozambique on reform of the commercial code, 2000
Advisor on Reformation and Rewriting of the Commercial Code

Instructor, South Asia Forum for Infrastructure Regulation, 1999-present
Annual Training Regulatory Personnel from Five South Asian Countries

Consultant, Government of Tanzania on electricity regulation, 2002
Advisor of Rewriting the Laws Governing Energy and Transport Regulation

Consultant to Inter-American Development Bank on Sustainability of Sector Reform in Latin American energy markets, 2001-2002
Preparation of a report and Analysis on the Sustainability of Power Sector and Regulatory Reform in Latin America, with Specific Focus on Colombia, Honduras, and Guatemala

Consultant to Inter-American Development Bank, Brazilian Electric Restructuring, 2002
Preparation of A Report and Analysis on Problems in the Privatization and Market Reform on the Brazilian Power Sector

Consultant to World Bank on Brazilian energy regulation, 2002-2004
Preparation of A Report and Analysis of Means for Improving Regulation of the Brazilian Power Sector.

Consultant to the Brazilian Government on Redesign of Electricity Market, 2003-2004
Advisor to Ministry of Mines and Energy on Electricity Market Design

Consultant to Government of Dominican Republic on Electricity Regulation, 2004
Delivery of a Series of Lectures on Problems in Restructuring and Privatization in Dominican Power Sector

Consultant to Eskom, South Africa, 2004-2005
Advisor on to Eskom on Restructuring of South African Electric Distribution Sector

Consultant to World Bank on Regulation and Market Reform in Russian Power Sector, 2004-2005
Preparation of Report and Lecture on Regulatory Issues in proposed New Market Design of Russian Power Sector, and Attraction of Private Capital

Consultant to Government of Guinea-Bissau on Infrastructure Regulation, 2005
Training Government and Industry Personnel on Infrastructure Regulation

Consultant to the Government of Mozambique on Electricity Regulation, 2006-2007
Assisting in the Re-Establishment of the Electricity Regulatory Agency

Consultant to the Government of Equatorial Guinea, 2007
Assisting in writing the country's electricity law

Consultant to the Public Utilities Commission of Anguilla, 2008
Report on Funding Regulatory Agencies

Languages: English, Knowledge of Spanish and Portuguese

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THE ECONOMIC IMPACT OF DISTRIBUTED SOLAR IN THE APS SERVICE TERRITORY, 2016-2035

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FINAL REPORT

February 16, 2016

L. WILLIAM SEIDMAN RESEARCH INSTITUTE

The L. William Seidman Research Institute serves as a link between the local, national, and international business communities and the W. P. Carey School of Business at Arizona State University (ASU).

First established in 1985 to serve as a center for applied business research alongside a consultancy resource for the Arizona business community, Seidman collects, analyzes and disseminates information about local economies, benchmarks industry practices, and identifies emerging business research issues that affect productivity and competitiveness.

Using tools that support sophisticated statistical modeling and planning, supplemented by an extensive understanding of the local, state and national economies, Seidman today offers a host of economic research and consulting services, including economic impact analyses, economic forecasting, general survey research, attitudinal and qualitative studies, and strategic analyses of economic development opportunities.

Working on behalf of government agencies, regulatory bodies, public or privately-owned firms, academic institutions, and non-profit organizations, Seidman specializes in studies at the city, county or state-wide level. Recent and current clients include:

- *Arizona Commerce Authority (ACA)*
- *Arizona Corporation Commission (ACC)*
- *Arizona Department of Health Services (ADHS)*
- *Arizona Dept. Mines and Mineral Resources*
- *Arizona Hospital and Healthcare Association*
- *Arizona Investment Council (AIC)*
- *Arizona Mining Council*
- *Arizona Public Service Corporation (APS)*
- *Arizona School Boards Association*
- *Arizona Town Hall*
- *Arizona 2016 College Football Championship*
- *Banner Health*
- *BHP Billiton*
- *The Boeing Company*
- *The Boys & Girls Clubs of Metro Phoenix*
- *The Central Arizona Project (CAP)*
- *Chicanos Por La Causa*
- *The City of Phoenix Fire Department*
- *CopperPoint Mutual*
- *Curis Resources (Arizona)*
- *De Menna & Associates*
- *Dignity Health*
- *The Downtown Tempe Authority*
- *Environmental Defense Fund*
- *Epic Rides/The City of Prescott*
- *Excelsior Mining*
- *Executive Budget Office State of Arizona*
- *The Fiesta Bowl*
- *First Things First*
- *Freeport McMoRan*
- *Glendale Community College*
- *Greater Phoenix Economic Council*
- *HonorHealth*
- *Intel Corporation*
- *iState Inc.*
- *The McCain Institute*
- *Maricopa Community Colleges*
- *Maricopa Integrated Health System*
- *Navajo Nation Div. Economic Development*
- *The Pakis Foundation*
- *Phoenix Convention Center*
- *The Phoenix Philanthropy Group*
- *Phoenix Sky Harbor International Airport*
- *Protect the Flows*
- *Public Service New Mexico (PNM)*
- *Raytheon*
- *Republic Services, Inc.*
- *Rio Tinto*
- *Rosemont Copper Mine*
- *Salt River Project (SRP)*
- *Science Foundation Arizona (SFAZ)*
- *Tenet Healthcare*
- *The Tillman Foundation*
- *Turf Paradise*
- *Valley METRO Light Rail*
- *Tenet Healthcare*
- *Twisted Adventures Inc.*
- *Vote Solar Initiative*
- *Waste Management Inc.*
- *Yavapai County Jail District*

Executive Summary

- This study examines the economic impact of three distributed (rooftop) solar deployment scenarios in the APS service territory for the study period 2016-2035, including the legacy effects of each scenario throughout the (assumed) 30 year economic life of distributed solar systems.[1]

- When considered in the round from a purely financial perspective, it concludes that all three potential distributed solar deployment scenarios will have a detrimental effect on the State of Arizona and Maricopa County economies, all other things being equal.

- Additional distributed solar is estimated to lower gross state product (GSP) by approximately $4.8 billion to $31.5 billion (2015 $), dependent on the scenario.

- Additional distributed solar deployment is also estimated to result in the net loss of 16,595 to 116,558 job years' private non-farm employment over the entire study period, dependent on the scenario.

- Any benefits emanating from each scenario are at best temporary, only coincident with the timing of the solar installations, and quickly counteracted by their long-run/legacy effects.

- In all three scenarios, the total amount of money paid by distributed generation and central station generation electricity consumers, 2016-2060, is greater than the amount which would have been paid had they all alternatively continued to draw electricity from the utility's central grid.

- That is, in each distributed solar scenario, electricity consumers as a whole will pay more for the same amount of electricity consumed, and therefore have less money to spend in other parts of the economy.

[1] The study assumes that the cost of a 2035 distributed solar installation will only be paid off in full in 2065, thereby accounting for legacy effects. If the economic life of an installation is less than 30 years, the negative economic consequences will be greater.

LITERATURE REVIEW

- The study begins with a comprehensive literature review to assess state-of-the-art methods in economic impact analysis.

- Seidman's methodological approach is initially positioned in a 3 x 2 matrix classification of economic impact studies, illustrated below.

Seidman's 3 x 2 Classification of Economic Impact Models

COUNT GROSS	**PARTIAL GROSS**	**GENERAL GROSS**
COUNT NET	**PARTIAL NET**	**GENERAL NET**

- ***Gross*** studies only consider the direct positive impacts of increased economic activity in a specific sector.

- ***Net*** studies represent a more thorough form of economic modeling as they also account for the trade-offs in the economy which result from incentivizing one specific sector.

- ***Counts*** are usually survey-based or theoretical capacity installation quantifications of the number of direct employees within one specific sector.

- ***Partial*** models consider the wider effects of levels of activity in one specific sector, including the indirect and induced effects of the direct change, but do not consider the feedback effects of changed levels of activity in that sector – for example, the effect on wages in the labor market.

- ***General*** models offer the most comprehensive economy-wide analysis, taking into account all of the economic interconnections and feedback effects. They also yield the most significant ***Gross*** and ***Net*** impacts.

- A critique of fourteen contemporary solar economic impact studies identifies only one example of a general equilibrium analysis – that is, Cansino, Cardenete, Gonzalez and Pablo-Romero's (2013) study of Andalusia. However, this is a gross, rather than net analysis, because the authors combine renewables and non-renewables as a single sector, thereby preventing any substitution between conventional and renewable forms of generation, and effectively only allowing for positive direct demand shocks in their modeling.

- Nine of the fourteen critiqued papers adopt the partial model approach, but six of these are gross, rather than net, studies.

Positioning Seidman's Approach Relative to Fourteen Contemporary Economic Impact Studies

	Counts	**Partial Models**	**General Models**
Gross ***Only positive or negative impacts***	• Pollin and Garrett-Peltier, 2009 • ETIC, 2016	• AECOM, 2011 • Loomis, Jo & Alderman ,2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al. , 2014	• Cansino et al. 2013
Net ***Both positive and negative impacts***	• Alvarez et al., 2009 • Frondel et al., 2009	• NYSERDA, 2012 • Treyz et al., 2011 • Berkman et al.,2014 • **SEIDMAN 2016**	

- In the absence of an existing CGE model for the State of Arizona, and taking into account time and cost constraints, Seidman implements a ***Partial Net*** REMI analysis of solar deployment in the APS service territory, 2016-2035, as the next best alternative.

ECONOMIC IMPACT ANALYSIS

- The capital costs and financing implications of each distributed solar deployment scenario are first estimated by APS, validated by Seidman, and allocated by economic sector using NREL's JEDI model for distributed solar installations throughout the supply chain in the State of Arizona.

- APS also supplied data describing the financial impact of each solar deployment scenario on its operating cash flow, future central station generation investments, and retail electricity rates.

- The changes in investment included in the economic impact model are:

    - The annual installed costs of distributed solar capacity, 2016-2035;[2] and
    - APS' deferred or avoided central station generation investments, 2016-2035.

- The long-term legacy costs of the investment included in the economic impact model are:

    - The customer financing costs of distributed solar installations, 2016-2060;[3] and
    - Consumer electricity rate savings, due to the deferred or avoided central station generation, 2016-2060.

- The results for each scenario take into account the direct, indirect and induced economic impacts of the distributed solar deployment, and the 30-year legacy effects reflecting the economic life of the solar installations and deferred central station generation.

- Using an Arizona-specific REMI model, the economic impact of the low case scenario, which assumes 1,300 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:[4]

LOW CASE SCENARIO	Total Private Non-Farm Employment (Job Years)[5]	Gross State Product (Millions 2015 $)	Real Disposable Personal Income (Millions 2015 $)
State of Arizona	-16,595	-$4,806.6	-$1,787.3
Maricopa County	*-15,685*	*-$4,491.8*	*-$1,862.4*

[2] APS assumes an initial $2.50 a watt.
[3] Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.
[4] Total effects for each economic measure may not tally due to rounding-up.
[5] A job year is equivalent to one person having a full-time job for exactly one year.

- If the low case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 16,595 job years of employment, plus over $4.8 billion gross state product, and $1.8 billion real disposable personal income (both 2015 $).

- The low case distributed solar scenario therefore estimates negative impacts for all three economic impact measures assessed for the study period, including legacy effects, in the State of Arizona and Maricopa County.

- The economic impact of the expected or medium case scenario, which assumes 5,000 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:[6]

EXPECTED CASE SCENARIO	Total Private Non-Farm Employment (Job Years)[7]	Gross State Product (Millions 2015 $)	Real Disposable Personal Income (Millions 2015 $)
State of Arizona	**-76,308**	**-$21,613.3**	**-$7,956.4**
Maricopa County	***-71,344***	***-$20,149.9***	***-$8,087.9***

- If the expected or medium case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 76,308 job years of employment, plus over $21.6 billion gross state product, and approximately $8 billion real disposable personal income (both 2015 $).

- The expected or medium case distributed solar scenario's negative impacts for all three economic measures are approximately 4.5 times greater than the low case scenario's impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.

- The economic impact of the high case scenario, which assumes 7,600 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:[8]

[6] Total effects for each economic measure may not tally due to rounding-up.
[7] A job year is equivalent to one person having a full-time job for exactly one year.
[8] Total effects for each economic measure may not tally due to rounding-up.

HIGH CASE SCENARIO	Total Private Non-Farm Employment (Job Years)[9]	Gross State Product (Millions 2015 $)	Real Disposable Personal Income (Millions 2015 $)
State of Arizona	-116,558	-$31,454.4	-$11,901.4
Maricopa County	*-108,857*	*-$29,346.7*	*-$12,091.2*

- If the high case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 116,558 job years of employment, plus $31.5 billion gross state product, and $11.9 billion real disposable personal income (both 2015 $).

- The high case distributed solar scenario's negative impacts for all three economic measures are 6.5 to 7 times greater than the low case scenario's impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.

- The high case distributed solar scenario's negative impacts for all three economic measures are also 46% to 53% greater than the expected or medium case scenario's impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.

- Seidman's APS study therefore clearly demonstrates that increased adoption of distributed solar generation represents a loss to the Arizona economy in the low, expected and high distributed solar deployment scenarios. This is because the overall cost of provision of electricity to the State of Arizona will rise when referenced against a base case where electricity continues to be provided by central station generation.

[9] A job year is equivalent to one person having a full-time job for exactly one year.

Table of Contents

1.0 Introduction

The purpose of this study is to calculate the total (net) economic impact of an APS distributed solar NEM program in Arizona up to and including 2035.

1.1. Net Metering

Net metering (NEM) encourages consumers to invest in renewable energy technologies by crediting them for distributed generation at the same tariff they pay for purchasing centrally-generated power.

Originating in Idaho and Arizona in the early 1980s, this utility resource usage and payment scheme allows customer meters to effectively run backwards whenever their own generation is in excess of their level of consumption.

Customers use their generation to offset their consumption over an entire billing period, and only pay for their net power purchase per month: that is, the amount of electricity consumed minus the amount of electricity generated. NEM credits are, de facto, based on current centrally-generated power tariffs.

Some suggest that NEM unfairly passes on the fixed costs of building and operating a transmission grid used by participants to non-participating customers. This is because residential and small business' utility rates volumetrically recover all costs, including those that are fixed. Advocates typically counter this criticism by arguing that NEM customers bring benefits to the grid that equal or exceed the fixed costs they avoid paying for through self-generation, including job creation and other economic impacts.

NEM is currently available in Arizona for a wide range of distributed generation renewables, including solar PV, solar thermal, wind, biomass, biogas, hydroelectric, geothermal, combined heat and power, and fuel cell technologies. The Arizona Corporation Commission (ACC) has not set a firm kilowatt-based limit on system size capacity. It simply stipulates that a system size cannot exceed 125% of a customer's total connected load or electric service drop capacity. There is also no aggregate capacity limit for net-metered systems in Arizona. However, each utility is obliged to file an annual report listing the net metered facilities and their installed capacity for the previous calendar year. Approximately 38,000 of APS' current 1.2 million customer base have distributed solar.

1.2. Economic Impact Analysis

An economic impact analysis measures the effect of a policy, program, project, activity or event on a national, state or local economy, with particular emphasis on three types of effects or impacts. These are the *direct*, *indirect* and *induced* impacts:

- ***Direct*** impacts include the initial capital investment when a business, policy or program is launched, and the people directly employed to manufacture a product, provide a service or deliver a program.
- ***Indirect*** impacts are the economic growth or decline resulting from inter-industry transactions or supplier purchases, such as a distributed solar installation company's purchase of solar modules.
- ***Induced*** impacts occur when the workers either directly or indirectly associated with an organization, policy or program spend their incomes in the local economy, when suppliers place upstream demands on other producers, and when state and local governments spend new tax revenues.

The indirect and induced economic impacts are second order expenditures and jobs created as a result of the initial "injection" of expenditure and direct jobs. For example, a utility employee hired to administer a NEM program would represent a *direct* job. Purchases made by a utility are *indirect* impacts; and the income that the utility or supplier companies' employees spend in the local economy will in turn create revenues/income for a variety of other businesses, generating *induced* effects.

The second and later rounds of indirect and induced expenditure are not self-perpetuating in equal measure. Through time, they become smaller as more of the income/expenditures "leak" out of the examined economy.[10] The cumulative effect of the initial and latter rounds of expenditure is known as the multiplier effect. There is no one "magic" multiplier estimate for every conceivable scenario. Due to the inter-linked nature of the State of Arizona's economy and its links to the rest of the U.S. (and the world), the eventual ripple effects depend on numerous factors.[11]

A full understanding of the total impact that a specific energy policy will have on an economy is therefore rather more complex than just an extrapolation of direct impacts.

[10] For example, in the form of savings, or payments on goods and services produced outside of the state.
[11] In very simple terms, what matters is the size of the direct impact, where it occurs (that is, which county/state and which sector of the economy) and the duration of the impact.

1.3. Study Overview

To help position APS' service territory study and provide a context for its findings, Section 2 begins with an overview of economic impact modelling approaches to renewable energy, summarized in the form of a 3 x 2 matrix.

Fourteen published analyses drawn primarily, but not exclusively, from the U.S., and additional insights from Canada, Germany, and Spain (listed in Table 1) are reviewed by Seidman in Section 3, with a particular focus on assumptions, methods and conclusions.

Examining the varying magnitude of the employment and gross state product (GSP) impacts for each of the different types of study defined by the economic impact model matrix in Section 4, a clear rationale for Seidman's approach to assess the economic impact of distributed solar deployment in the APS service territory is also provided.

Sections 5 – 9 then examine the economic impact of three distributed (rooftop) solar deployment scenarios in the APS service territory for the study period 2016-2035 in the State of Arizona and Maricopa County. The analyses include the legacy effects of each scenario throughout the (assumed) 30 year economic life of the solar systems.[12]

Section 5 introduces the 3 solar deployment scenarios assessed for APS. These are:

- A low case scenario, which assumes 1,300 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 150,000 accounts;
- An expected or medium case scenario, which assumes 5,000 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 690,000 accounts; and

[12] Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

- A high case scenario, which assumes 7,600 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 1,050,000 accounts.

Table 1: Economic Impact Analyses Critiqued as Part of Current Study

Geography	Title & Author(s)
California	*AECOM (July 2011)* Economic and Fiscal Impact Analysis of Residential Solar Permitting Reform
California	*Vote Solar Initiative (April 2013)* Economic and Job Creation Benefits of SB 43/AB 1014
Illinois	*Loomis, Jo and Alderman (December 2013)* Economic Impact Potential of Solar Photovoltaics in Illinois
Montana	*Comings, Fields, Takahashi and Keith (June 2014)* Employment Effects of Clean Energy Investment in Montana
Montana	*Energy and Telecommunications Interim Committee (January 2016)* Quantifying the Economic Impacts of Net Metering in Montana
Massachusetts	*Motamedi and Judson (March 2012)* Modeling the Economic Impacts of Solar PV Development in Massachusetts
Missouri & U.S.	*Treyz, Nystrom and Cui (October 2011)* A Multiregional Macroeconomic Framework for Analyzing Energy Policies
Nevada	*Vote Solar Initiative and Clean Energy Project (2011)* Economic and Job Creation Benefits of the Nevada Solar Jobs Now Proposal of 2011
New York	*NYSERDA (January 2012)* New York Solar Study
Rhode Island	*Berkman, Lagos and Weiss (2014)* Distributed Generation Contracts Standard Program and Renewables Energy Fund: Jobs, Economic and Environmental Impact Study
Andalusia	*Cansino, Cardenete, Gonzalez, and Pablo-Romero (2013)* Economic Impacts of Solar Thermal Electricity Technology Deployment on Andalusian Productive Activities: A CGE Approach
Germany	*Frondel, Ritter, Schmidt and Vance (2009)* Economic Impacts from the Promotion of Renewable Energy Technologies - The German Experience
Ontario	*Pollin and Garrett-Peltier (2009)* Building the Green Economy: Employment Effects of Green Energy Investments for Ontario
Spain	*Alvarez, Jara, Julian and Bielsa (March 2009)* Study of the Effects on Employment of Public Aid to Renewable Energy Sources

Section 6 describes the simulation results for the low distributed solar deployment scenario.

Section 7 presents the simulation results for the expected distributed solar deployment scenario.

Section 8 describes the simulation results for the high distributed solar deployment scenario.

Conclusions are offered in Section 9.

2.0 Economic Impact Assessment Methods

There are a number of different approaches to an economic impact assessment. These are codified in Figure 1 below.

Figure 1: Classification of Economic Impact Models

COUNT GROSS	**PARTIAL GROSS**	**GENERAL GROSS**
COUNT NET	**PARTIAL NET**	**GENERAL NET**

Figure 1 illustrates two key distinctions among economic impact studies.

The first distinction is between gross studies and net economic impact studies. Studies that are ***Gross*** in nature only consider the direct *positive* impacts of increased economic activity – in this case, solar generation. ***Net*** studies represent a more rounded form of economic assessment because they also account for the trade-offs in the economy which result from incentivizing one specific sector, such as the *negative* impacts on utilities and reduced spending and investment in other economic activities associated with increased solar activity.

For example, a gross study might consider the positive effects of the installation of 100MW utility-scale solar on the level of economic activity alone, while a net study of the same installation would additionally allow for the negative economic impacts such as the decreased use of conventional forms of generation if these were displaced, and the net changes in residential, commercial and industrial energy bills. Consider also the installation of a distributed solar system by a homeowner. To meet a $30,000 cost of installation, the homeowner will forego spending the same $30,000 on something else, such as perhaps a new or refurbished swimming pool at their property. There are obviously positive economic effects associated with the homeowner's investment in a distributed solar system, which would be captured in a gross economic study. However, in this example, there are also negative effects associated with the loss of investment in the swimming pool, which are only ever considered alongside the positive benefits of the solar installation as part of a *net* study.

Nine gross and five net studies are examined in Section 3. The gross studies are:

- California: AECOM, 2011
- California: Vote Solar Initiative, 2013
- Illinois: Loomis, Jo & Alderman, 2013
- Massachusetts: Motamedi & Judson, 2012
- Montana: Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014
- Montana: ETIC, (2016)
- Nevada: Vote Solar Initiative, 2011
- Andalusia: Cansino, Cardenete, Gonzalez and Pablo-Romero, 2013
- Ontario: Pollin and Garrett-Peltier, 2009

The net studies are:

- Missouri & U.S.: Treyz, Nystrom and Cui, 2011
- New York: NYSERDA, 2012
- Rhode Island: Berkman, Lagos and Weiss (the Bratton Group), 2014
- Germany: Frondel, Ritter, Schmidt and Vance, 2009
- Spain: Alvarez, Jara, Julian and Bielsa, 2009

The second key distinction is between simple counts, partial (equilibrium) modeling, and macroeconomic (or general equilibrium) modeling.

Counts are typically tallies of direct measures of economic activities, such as jobs, investments, or sales, without any attempt to capture the impacts of the inter-relationships with other economic sectors. As a result, counts can be more or less extensive in terms of their reach. Some just concentrate on counting the number of direct employees or assessing the level of sales within a specific economic sector, while others seek information about a sector's entire supply chain. Counts can be made by surveys or by assessing theoretically the required inputs for the installation of defined amounts of solar capacity – for example, the first part of a JEDI model which estimates the number of jobs created in the solar sector in a linear fashion based on the MW capacity of the solar installations. Studies examined in this report that use the counts method are:

- Montana: ETIC, 2016
- Germany: Frondel, Ritter, Schmidt and Vance, 2009
- Ontario: Pollin and Garrett-Peltier, 2009
- Spain: Alvarez, Jara, Julian and Bielsa, 2009

Partial models consider the wider effects of levels of activity in a specific economic sector, and are one of the most common commercial approaches in economic impact modeling. In contrast to counts, which generally assess the direct impacts of a change in the economy, partial models also consider the indirect and induced effects of the direct changes within a particular geography. The one drawback with partial models is that they do not consider the feedback effects of changed levels of an investment or economic activity such as, for example, the effect of large solar projects on wages in the labor market. Studies examined in this report that use the partial model method are:

- California: AECOM 2011
- California: Vote Solar Initiative, 2013
- Illinois: Loomis, Jo & Alderman, 2013
- Massachusetts: Motamedi & Judson, 2012
- Missouri & U.S.: Treyz, Nystrom and Cui,, 2011
- Montana: Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014
- New York: NYSERDA, 2012
- Nevada: Vote Solar Initiative and Clean Energy Project Nevada, 2011
- Rhode Island: Berkman, Lagos and Weiss (the Bratton Group), 2014

General models consider the effects of levels of solar activity in an economy-wide context with reference to every economic interconnection and feedback effect. An example is computable general equilibrium (CGE) models. These model the entire economy and attempt to account for all of the impacts associated with a specific level of solar activity. Only one study examined in this report uses a general model to assess impacts, due to the cost prohibitive nature of producing a CGE model for a state or a region. This is Cansino, Cardenete, Gonzalez and Pablo-Romero's (2013) study of Andalusia.

Figure 2 summarizes the studies examined in this report in terms of the method employed, and whether they consider positive impacts alone, or both positive and negative impacts.

Figure 2: Classification of Studies Examined by Method

	Counts	Partial Models	General Models
Gross *Only positive or negative impacts*	• Pollin and Garrett-Peltier, 2009 • ETIC, 2016	• AECOM, 2011 • Loomis, Jo & Alderman ,2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al. , 2014	• Cansino et al. 2013
Net *Both positive and negative impacts*	• Alvarez et al., 2009 • Frondel et al., 2009	• NYSERDA, 2012 • Treyz et al., 2011 • Berkman et al., 2014	

3.0 Evaluation Framework and Review of Fourteen Economic Impact Analyses

To objectively critique fourteen contemporary analyses of the economic impact of solar PV/renewables, Seidman uses the following questions as an evaluation framework:

(a) What is the context for a study?
(b) What are the study's objectives?
(c) Which geography is being studied?
(d) What is the time-horizon of the study?
(e) Which economic modeling tool is used?
(f) What types of effects are modeled, with reference to Seidman's 3 x 2 classification of economic impact models?
(g) What are the key inputs and assumptions used in the modeling process, including the solar growth projection assumptions?
(h) What are the key findings?

The following tables in this Section provides Seidman's assessment of each of the fourteen contemporary studies.

Reference will also be made, where appropriate, when a particular study method is replicated in multiple geographies by the same authors.

Title	**Economic and Fiscal Impact Analysis of Residential Solar Permitting Reform**
Author(s)	**AECOM, July 2011**
Background	Considers the impact of a 76% reduction in homeowner permitting costs for solar PV when scaled to the regional and state level, taking into account the projected growth in the industry through 2020.
Objective(s)	• Evaluate the economic and fiscal implications of a streamlined local government permitting system for installing residential solar PV.
Geography	California
Time Period	2012-2020
Modeling Tool	IMPLAN

Type of Effects Examined	• This is a ***Partial Gross*** analysis, as it lacks detail on negative impacts considered.
	• Considers a few more factors than the VSI reports, such as the initial down payment for a solar system which is positioned as a loss to homeowner savings and a gain to the solar industry.
	• It is at best a weak, borderline example of a net partial study as it does not:
	  o Explicitly consider non-solar energy sector losses;
	  o Take into account utility obligations from a transmission and distribution grid perspective in terms of savings, upgrades or modifications;
	  o Quantify the impact of a reduction in the demand for centralized power generation due to increased distributed generation;
	  o Remove the rebate dollars paid to homeowners and installers from the IMPLAN inputs; and
	  o Consider the administrative costs associated with changing permitting rules.
	• Also questionably assumes that increased homeowner savings from reduced electricity bills will be spent in full in-state.

Model Assumptions	• Base case scenario uses California Solar Initiative's 2011 residential installation costs of \$6.97 per watt decreasing to \$3.63 per watt by 2020. • Streamlined permitting would reduce annual costs by \$0.38 per watt in 2020 (i.e. from \$6.10 per watt in 2011 to \$3.25 per watt in 2020). • Investment Tax Credit of 30% is assumed to continue through 2020. • Average size of residential solar systems was 5.6 kW, 2012-2020. • All solar systems will be purchased in California, albeit region unknown. • Assumes solar in both cases will appeal to homeowners whose annual electricity bills would be reduced by at least 5% post-installation. • Value of residential solar only impacts property taxes when the home is sold. • Buyers will pay on average 3.6% more for solar PV homes.
Solar Growth Projection Assumptions	• Projects 1,006,500 installations at 5 utilities' service areas for current permitting, 2012-2020; or an additional 131,500 installations for streamlined permitting. • 332 MW installed 2007-2011; 2,668 MW installed 2012-2020 without streamlined permitting (BAU case).

Effects Scaled per Year (2015 \$)	• Current permitting scenario assumes:
	  o 73.5 job years created per total MW installed, amounting to 196,020 job years in total for the entire 2012-2020 period;
	  o \$1.24 million GSP per MW per year (2015 \$); and
	  o \$69.70 per MW per year increase in additional sales tax, property tax, and payroll tax (2015 \$).

Title	**Economic and Job Creation Benefits of SB 43/AB 1014**
Author(s)	**The Vote Solar Initiative, April 2013**
Background	SB43 and AB 1014 are two shared renewable pilot programs to enable residential renters and commercial customers to subscribe via PG&E, SCE, and SDGE to an offsite renewable energy project and receive a utility bill credit in return.
Similar Studies	• VSI (2010) Colorado; • VSI (2011) Nevada; • VSI (2011) Iowa; and • The Solar Foundation (2013) Colorado.
Objective(s)	• Estimate the number of jobs created under SB 43/AB 1014, and the increased dollars that will subsequently circulate throughout the California economy.
Geography	California
Time Period	2014-2016 construction; 25 year lifetime O&M
Modeling Tool	JEDI (based on IMPLAN I-O) version January 3, 2013
Type of Effects Examined	• This is a ***Partial Gross*** analysis of two shared renewable programs. • Study does not consider net job creation. It simply details the cumulative employment benefits of both proposed shared renewable programs, without taking into account the potential loss of jobs in other energy sectors. • State sales tax revenue and instate economic activity results are also exclusively considered from a shared renewable program perspective. • Authors ignore the net changes that will in reality occur due to changes in other sectors of the state economy prompted by both programs, including the potential for higher energy bills.

Model Assumptions	• Crystalline Silicon – fixed mount commercial; single axis tracking utility scale.
	• For both pilots, study assumes the following local purchases:
	  o 100% of components for solar installations < 100 kW;
	  o 50% of components for 100 kW to 1 MW installations; and
	  o 30% of components for installations > 1 MW.
	• For both pilots, it also assumes the following local manufacturing:
	  o 10%-20% of components for installations < 1 MW; and
	  o 5-10% of components for installations > 1 MW.
	• This amounts to 546 MW local total purchases for the implementation of both pilot schemes, and 91.5 MW to 183 MW local manufacturing.
	• 2014-2016 construction period.
	• 25 year operational phase.

Solar Growth Projection Assumptions	• For SB 43, 53 MW installed in 2014, 161 MW installed in 2015, and 286 MW installed in 2016, resulting in a 500 MW pilot. • For AB 1014, 65 MW installed in 2014, 285 MW installed in 2015, and 650 MW installed in 2016, resulting in a 1,000 MW pilot.
Effects Scaled per Year (2015 $)	• SB 43 is estimated to have a gross jobs impact of 26.7 job years/MW, $179,000 GSP per MW per year, and $5,291 sales tax revenue per MW per year (2015 $). • AB 1014 is estimated to have a gross jobs impact of 24.0 job years/MW, $175,000 GSP per MW per year, and $5,331 sales tax revenue per MW per year (2015 $).

Title	**Economic Impact Potential of Solar Photovoltaics in Illinois**
Author(s)	**Loomis, Jo and Alderman, December 2013**
Background	Center for Renewable Energy (Illinois State University) study, supported by an Illinois Department of Commerce and Economic grant.
Objective(s)	Considers employment and output impacts for the construction and operations phases of 3 solar deployment scenarios, with 3 levels of in-state manufacturing.
Geography	Illinois
Time Period	2014-2030
Modeling Tool	JEDI PV Model (PVS4.5.13)
Type of Effects Examined	• This is a ***Partial Gross*** analysis. • It exclusively considers renewable (solar) sector impacts, including supply chain. • It does not consider corresponding impacts in other parts of the energy sector, or other economic sectors.
Model Assumptions	• Installations profile: o 10% residential (80% retrofits, 20% new construction); o 10% small commercial; o 20% large commercial; o 60% utility-scale. • 100% local purchases: o Labor and soft costs (permitting and business overhead); and o Residential and small commercial materials and equipment. • All materials and equipment for large commercial and utility-scale installations are purchased 100% out-of-state. • Three levels of instate manufacturing per scenario – 0%, 5%, and 10%.
Solar Growth Projection Assumptions	• 2,292 MW, 2714 MW, or 11,265 MW by 2030.
Effects Scaled per Year (2015 $)	• For all 3 scenarios at 10% in-state manufacture: o 12.2 gross job years per MW installed; o Approximately $107,000 GSP per MW per year (2015 $); and o Approximately $45,600 labor income per MW per year (2015 $).

Title	**Modeling the Economic Impacts of Solar PV Development in Massachusetts**
Author(s)	**Motamedi and Judson, March 28, 2012 (Unpublished PowerPoint)**
Background	REMI. commission for the New England Energy and Commerce Association Renewables and Distributed Generation Committee.
Objective(s)	• Assess the economic impact of the o Construction of 305 MW of solar PV, 2012-2018; and o Operation of solar PV installations, 2012-2025.
Geography	Massachusetts
Time Period	• 2012-2018 construction; and • 2012-2025 operations.
Modeling Tool	REMI
Type of Effects Examined	• ***Partial Gross*** study, which generically describes, but does not state, the value of inputs used.[13] • Energy cost savings are only considered from a solar savings perspective.
Model Assumptions	• Combination of residential, commercial, and utility-scale solar installations, with regional purchase coefficients of 0.629, 0.564, and 0.580 respectively. • Construction phase uses total investment after federal and state tax credit cost reduction, including some consumer consumption reallocation and production costs, along with consumer electricity price, and business electricity fuel cost changes. • Models locally supplied inputs as total construction spending. • Consumer price of electricity, electricity fuel costs for businesses, and production cost to utilities are used to represent the energy cost savings; and analysis assumes no change to SREC market.
Solar Growth Projection Assumptions	• Additional 305 MW of PV, 2012-2018, taking total installation to 400 MW. • Does not state the split between residential, commercial and utility-scale solar.
Effects Scaled per Year (2015 $)	• 20.1 job years created per MW installed. • Approximately $122,000 GSP per MW per year (2015 $). • Approximately $155,000 personal income per MW per year (2015 $).

[13] Motamedi and Judson mention energy cost savings, implying some consideration of the negative economic impacts of solar deployment. However, their PowerPoint presentation does not include any obvious assessment of negative impacts, and the REMI output is not suggestive of their inclusion. As a result, Seidman has classified their approach as ***Partial Gross***.

Title	**A Multiregional Macroeconomic Framework for Analyzing Energy Policies**
Author(s)	**Treyz, Nystrom and Cui, October 2011**
Background	REMI-authored study considering the local, regional and national economic impacts of Missouri's RPS, excluding environmental and social impacts.
Objective(s)	Compares effects of electricity price-cap mandate (Scenarios 1 and 2) and an alternative bond-funded cost-recovery strategy (Scenarios 3 and 4) to finance the subbing of wind and solar for coal.
Geography	Missouri and the U.S.
Time Period	• Construction impacts (RPS implementation), 2011-2021. • Operational impacts, 2011-2035.
Modeling Tool	REMI
Type of Effects Examined	• ***Partial Net*** study.
Model Assumptions	• Baseline: No RPS implemented in Missouri. • Scenario 1 = IOUs raise prices to statutory cap of 1% to recover low cost of subbing wind and solar for coal (cost fully recovered by 2023). • Scenario 2 = IOUs raise prices to statutory cap of 1% to recover high cost of subbing wind and solar for coal (cost fully recovered by 2025). • Scenario 3 = IOUs issue bonds with maturity of 15 years at 3.25% interest rates to raise funding needed for low cost infrastructure. • Scenario 4 = IOUs issue bonds with maturity of 15 years at 3.25% interest rates to raise funding needed for high-cost infrastructure. • In Scenarios 1 and 2: o 1% compound increase in commercial and industrial electricity prices; o 1% compound increase in residential electricity prices, with lower disposable income corresponding consumption reallocation. • In Scenarios 3 and 4: o Utilities issue bonds at bank prime rate of 3.25% per year for 15 years; o Impacts greater in the 2020s when consumers have to pay higher prices to pay off bonds, compared to 2010s when consumers pay the costs up front in Scenarios 1 and 2. • In Scenarios 1-4: o Solar panel purchase and O&M are treated as semiconductor manufacture exogenous final demand with corresponding consumption reallocation o IOU rebates accounted for in production cost and transfer payments; o Partial substitution of conventional electricity for solar electricity allows households to reduce conventional electricity consumption and expense, captured in consumption reallocation; and o Creation of a custom industry for commercial wind generation, to account for different intermediate demands.
Solar Growth Projection Assumptions	• RPS: Coal = 66%, Wind 14.7%, Solar 0.3% and Other 20% from 2021 onwards. • Coal declines from 81% of electric production in 2010 to 66% by 2021; wind and solar from 0% to 15%.
Effects Scaled per Year (2015 $)	• Graphs rather than data tables are provided, creating difficulties for interpretation. • A state RPS is assumed to cause a short-term decrease in local employment, real GDP and personal real disposable income per capita. • Raising electricity prices is estimated to result in the loss of 4,000 to 5,000 job years by 2021 or 2025, before recovering to the same level as the 2010 baseline in 2031. • A bond scheme is estimated to create an initial short term annual employment increase of up to 1,000 jobs, but the trend reverses upon completion of the RPS in 2021,

[redacted]	decreasing by 2,000 to 3,000 jobs per year up until 2027, before recovering to a net decrease of 600-800 jobs by 2035. • Real GDP would steadily decrease under the price-cap scenario, hitting a low of $350-$458 million loss in 2021 and 2025, before regaining some ground to a $102 million loss in 2035 (2015 $). • The utility bond approach would have expand real GDP until 2021, peaking at $153-$204 million in 2019, fading to a decrease of $306-$408 million in 2027, before picking up to a loss of $153-244 million by 2035 (2015 $).

Title	**Employment Effects of Clean Energy Investment in Montana**
Author(s)	**Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014**
Background	Examines the employment impacts of hypothetical additions to Montana's renewable energy portfolio.
Objective(s)	• Estimate employment impacts of construction and O&M activities associated: o Large-scale wind; o Large-scale solar PV; o Small-scale solar PV (rooftop), and o Energy efficiency.
Geography	Montana
Time Period	• Installation of systems is assumed to take place in 2016-2017. • Assumes 20 years of system operation.
Modeling Tool	IMPLAN in conjunction with capacity data from NREL's JEDI model.
Type of Effects Examined	• ***Partial Gross*** study of direct, indirect and induced employment impacts. • Makes no attempt to consider net effects. Focused entirely on job impacts of solar installation and O&M spending and considers no other benefits of solar deployment.
Model Assumptions	• Develops solar spending patterns associated with rooftop and utility-scale installations using NREL's JEDI model with adjustments for local conditions. • Estimates construction jobs in short-run and allocates them over 20 years together with O&M to obtain a 20 year cumulative job impact per average MW deployed.
Solar Growth Projection Assumptions	• No actual projections. • Uses NREL's (2012) maximum hypothetical potential of 4,409 GW utility-scale and 2 GW rooftop solar PV for Montana.
Effects Scaled per Year	• Small PV – 9.2 job years per MW. • Large PV – 5.0 job years per MW.

Title	**Quantifying the Economic Impacts of Net Metering in Montana**
Author(s)	**Energy and Telecommunications Interim Committee (ETIC), January 2016**
Background	Examines the historical economic development impact of net metering installations in 2014 and 2000-14 in Montana.
Objective(s)	• Evaluate economic development impacts of the installation of net metering systems in terms of the following benefits and costs: o Bill savings of net metering customers; o Residential property value increases; o Revenue generated by installations; o Employment from installations; o Value of avoided carbon emissions; o Costs of income tax credits; and o Universal System Benefits (USB) renewable energy and Research & Development (R&D) allocations.
Geography	Montana
Time Period	2000-2014
Modeling Tool	Counts based on survey/modeling estimates from other states.
Type of Effects Examined	• This is in fact not an economic impact study or a normal assessment of economic development impacts. • It's a partial ***Count Gross*** analysis that considers a limited set of costs and benefits associated with net metering system deployments. • The tax revenue estimates are unclear, incomplete and based on very general assumptions.
Model Assumptions	• Based mostly on Montana Renewable Energy Association (MREA) survey data. • Uses NREL models to assess installation sales revenue based total installations each year but no specifics of the nature of the system(s) installed are given. • Employment outcomes are also based on survey work done by the Montana Environmental Information Center, Synapse Energy and the Sierra Club. • It is lacking in a number of aspects. It needs to: o Consider *full* indirect and the induced impacts of net metering; o Use appropriate bespoke models for Montana reflective of local economic circumstances; and o Not rely on very general rule of thumb estimates for jobs, revenues and taxes generated as base data. • It double-counts historical property value and homeowner energy savings as separate benefits.
Solar Growth Projection Assumptions	• The extent of net metering systems installed in 2014 is stated as \$4M (2014 \$) but there is no statement of the extent of system additions or their capacity between 2010 and 2014.
Effects Scaled per Year	• There is no statement of installed capacity during the study period. There is also no statement of GSP, employment or tax revenue. It is thus impossible to calculate a jobs impact per MW, GSP per MW per year, or sales tax revenue per MW.

Title	**Economic and Job Creation Benefits of the Nevada Solar Jobs Now Proposal of 2011**
Author(s)	**Vote Solar Initiative and Clean Energy Project Nevada**
Background	Considers the economic impact of expanding Nevada's DG solar market from 35 MW to 400 MW between 2011 and 2020.
Similar Studies	• VSI (2010) Colorado; • VSI (2011) Iowa; • VSI (2013) California; and • The Solar Foundation (2013) Colorado.
Objective(s)	• Evaluate the economic, job benefits and tax impacts of expansion of and changes to the incentive structure of Nevada's Solar Jobs Now proposal of 2011.
Geography	Nevada
Time Period	2011-2020
Modeling Tool	NREL's Jobs and Economic Impacts (JEDI) model.
Type of Effects Examined	• This is a very simplistic and rather opaque ***Partial Gross*** analysis since it lacks *any* consideration of the negative impacts of expansion. • It is biased in terms of its assessment of economic impacts since it does not: o Consider any non-solar energy sector losses; o Take into account utility obligations from a transmission and distribution grid perspective in terms of savings, upgrades or modifications; o Quantify the impact of a reduction in the demand for centralized power generation due to increased distributed generation; o Consider the economic impacts of rebate dollars paid to DG homeowners and installers; o Examine the economic impacts of reduced spending on other categories of expenditure throughout the expansion phase from capital expenditures on DG solar systems; and o Consider the administrative costs associated with changing permitting rules.
Model Assumptions	• Base assumptions are drawn from a JEDI model specific to Nevada. • Basic premise is a growth of 365 MW in residential and commercial DG solar. • No specifics about system characteristics used in the JEDI model are outlined in the paper.
Solar Growth Projection Assumptions	• 365 MW installed 2011-2020.
Effects Scaled per Year (2015 $)	• Over the period 2011-2020, The Solar Jobs Now Proposal is estimated to have: o A gross jobs impact of 28.5 job years/MW; o $443,400 GSP per MW per year (2015 $); and o $22,500 sales tax revenue per MW (2015 $).

Title	**New York Solar Study**
Author(s)	**New York State Energy Research & Development Authority (NYSERDA), January 2012**
Background	Study required by The Power New York Act of 2011.
Objective(s)	Evaluate the cost-benefits of increasing solar PV in NY to 5,000 MW by 2025.
Geography	New York State
Time Period	2013-2049
Modeling Tool	REMI

Type of Effects Examined	• ***Partial Net*** study.
	• Quantifies direct PV job impacts of each scenario, economy-wide net impacts, gross state product, retail rate impacts, and environmental impacts.
	• Economy-wide net job analysis includes:
	  o Positive impacts such as the creation of new PV jobs, and ratepayer savings when electricity prices are suppressed by PV output; and
	  o Negative impacts, such as the cancellation of new power plants that are made unnecessary by the added PV capacity, or the additional costs of PV incentives, which reduce personal disposable income.
	• Net retail impact of PV deployment includes:
	  o The above-market costs of PV;
	  o Net metering costs; and
	  o Savings generated by the suppression of wholesale electricity prices.
	• Net environmental impacts include:
	  o Lower emissions via a reduction in the need for fossil fuel plants; and
	  o Land use changes from rooftop to ground-mounted over time.

Model Assumptions	• Three scenarios:
	  o Low Cost Scenario, using DOE SunShot goal for PV cost reduction, assuming extension of the federal tax credit (FTC) through 2025;
	  o Base Case Scenario, using a DOE survey and moderate reduction of FTC beyond 2016, plus costs of $2.5 million/MW for large-scale and $3.1 million/MW for small-scale installations; and
	  o High Case Scenario, based on the national average annual PV system price decline over the past decade, with FTC reverting to a pre-federal stimulus level in 2016.
	• 5% of solar components are manufactured in NY; the rest are imported.
	• Incentive costs are recovered from ratepayers through their electricity bills.
	• Quantified benefits of the 5000 MW by 2025 goal include a wholesale price suppression assumption, a reduction in energy lost to transmission and distribution inefficiencies, a reduction or deferral of the need to upgrade the utility distribution system, avoided RPS compliance costs, and a monetized carbon value of $15 per ton.

Solar Growth Projection Assumptions	• Achieve 5,000 MW solar PV deployment by 2025.
	• Four policy options are analyzed to stimulate demand:
	  o Utilities obliged to purchase tradable solar renewable energy credits (SRECs) from spot market, supported by a price floor mechanism to provide greater degree of revenue certainty;
	  o Utilities manage a competitive procurement similar to CA in which they award long-term contracts to purchase renewable energy;
	  o Residential and commercial small PV system rebates, and larger systems incentives, provided centrally via competitive bidding; and
	  o Utilities incentives for larger projects through competitive long-term contracts, and a cents per kWh produced for smaller projects.

Effects Scaled per Year (2015 $)	• 4.7-6.3 gross job years created per MW installed, dependent on scenario, 2013-2025. • 700 economy-wide jobs net gain (low) or 750 to 2,500 economy-wide jobs net loss (base and high), 2013-2049. • $15,760 GSP per MW per year gain (low), or $16,930 to $58,386 GSP per MW per year loss (base and high), 2013-2049 (2015 $).

Title	**Distributed Generation Standard Contracts Program and Renewables Energy Fund: Jobs, Economic and Environmental Impact Study**
Author(s)	**Berkman, Lagos and Weiss (The Brattle Group), 2014**
Background	• Prepared for the Rhode Island Office of Energy Resources and Commerce as stipulated by the July 2013 Distributed Generation Standard Contracts (DGSC) Law.
Objective(s)	• Examine the potential economic, fiscal and environmental impacts of the Distributed generation Standard Contract (DGSC) and Renewable Energy Fund (REF) 20134-2038.
Geography	Rhode Island
Time Period	2014-2038
Modeling Tool	IMPLAN in conjunction with energy capacity planning and energy dispatch models
Type of Effects Examined	• A ***Partial Net*** study in terms of its economic impact assessment. • Includes spending on installations as a gross addition to final demand. • Does not net out the associated purchase/leasing costs which would likely swamp installation spending. • Includes payments to DGSC/REF participants but no allows no countervailing reduction in non-DGC ratepayers' spending. • Costs to ratepayers are assessed but not included in the economic impact assessment. • Assess central generation capacity and operating costs with a capacity planning and economic dispatch model.
Model Assumptions	• Includes both wind and solar renewable energy. • Operational life span of renewable resources assumed to be 25 years. • Source metrics for with and without DGC and REF scenarios obtained from past studies. • Use secondary sources to assess central generation and capacity costs using approximations rather than primary modeling. • It is unclear how DGSC/REF capacity deletions/additions are assessed to affect central generation costs.
Solar Growth Projection Assumptions	• Three (assumed not forecast) scenarios above 2013 40 MW are assessed: o 160 MW (by 2019) with REF of $800,000 in solar installations; o 200 MW (by 2019) with REF of $800,000 in solar installations; and o 1,000 MW (by 2024) with REF of $1,600,000 in solar installations.
Effects Scaled per Year (2015 $)	• Average annual GSP per MW: o 160 MW DGC:$191,790 GSP per MW (2015 $); o 200 MW DGC: $182,216 GSP per MW (2015 $); and o 1,000 MW DGC: $135,290 GSP per MW (2015 $). • Average annual job years per MW: o 160 MW DGC: 1.53 jobs; o 200 MW DGC: 1.465 jobs; and o 1,000 MW DGC: 1.095 jobs.

Title	**Economic Impacts of Solar Thermal Electricity Technology Deployment on Andalusian Productive Activities: A CGE Approach**
Author(s)	**Cansino, Cardenete, Gonzalez and Pablo-Romero, 2013**
Background	Annals of Regional Science published paper estimating the impact on productive activities of increasing the production capacity of two types of solar thermal plant in Andalusia.
Objective(s)	• To quantify the gross direct and induced productivity impacts of a single parabolic trough solar collector power plant and a single solar tower plant for the Andalusian economy. • To also quantify the gross direct and induced productivity impacts of both types of solar thermal technology based on the addition of 789 MW installed capacity by 2013 to comply with the Sustainable Energy Plan for Andalusia (PASENER).
Geography	Andalusia (Spain)
Time Period	• 2008-2013 installation; and 30 year estimated lifetime for each plant.
Modeling Tool	Static computable general equilibrium (CGE) model, consisting of 27 productive activities in the Andalusian economy.
Type of Effects Examined	• ***General Gross*** study.[14] • Describes gross economic impacts by sector, based on an enlarged electricity sector which combines renewables and non-renewables and prevents any substitution.
Model Assumptions	• Walrasian notion of competitive equilibrium, extended to include producers, households, government, and foreign sectors. • The single representative consumer maximizes a Cobb-Douglas utility function. • Government maximizes a Leontief utility function. • Foreign sector is modeled as a single sector that includes the rest of Spain, the European Union, and the rest of the world. • Benchmark equilibrium scenario includes a perfect inelastic supply of capital and positive unemployment rate, and a fixed level of government and foreign sector activities which allows relative prices, activity levels, public deficit and foreign trade deficit to work as exogenous variables. • Equilibrium is defined as an economic state in which the representative consumer maximizes his utility, the 27-sector productive activities maximize their profits after taxes, and public revenue is equal to the payments to the different economic agents. • Does not consider if Andalusia's gross output gains are at the expense of other states' output – e.g. from the crowding-out effect of power generation.

Solar Growth Projection Assumptions	• For the single plant analysis:
	  o 50 MW parabolic trough plant with 624 collectors; and
	  o 17 MW solar tower plant with 2,750 heliostats.
	• Estimated lifetime of each plant is 30 years.
	• For the PASANER scenario, to meet the 800 MW target by 2013 (789 MW additions), the model assumes 80% parabolic trough and 20% solar tower.

Effects Scaled per Year	• Scenario 1 (single plant additions) is estimated to result in an economy-wide gross productivity increase of 0.75% for the parabolic trough plant, or a 0.68% economy-wide gross productivity increase for the solar tower plant. • Scenario 2 (PASANER) is estimated to result in an economy-wide gross productivity increase of 35.37% over the 30-year lifetime of the parabolic trough and solar tower plant additions (30.81% parabolic trough; 4.57% solar tower).

[14] Cansino et al. use a 27-sector CGE model that is a general modeling representation of the Spanish economy, allowing for both positive and negative feedback effects of increased levels of solar penetration in Andalusia. However, they model renewables and non-renewables as a single sector that does not allow for substitution between forms of generation, which means that they are effectively only allowing for positive direct demand shocks in their modeling. This is why Seidman classifies their approach as a *General Gross* model.

Title	**Economic Impacts from the Promotion of Renewable Energy Technologies – The German Experience**
Author(s)	**Frondel, Ritter, Schmidt and Vance, 2009**
Background	Critically reviews cost and job implications of the Renewable Energy Sources Act (EEG) – the centerpiece of the German promotion of renewable energy. This guaranteed stable feed-in-tariffs (FITs) for up to 20 years, and also favorable conditions for investments in green electricity production for the long-term.
Objective(s)	To demonstrate the impact of government-backed renewable incentives for stimulating the economy
Geography	Germany
Time Period	2000-2020
Modeling Tool	Non-Applicable

Type of Effects Examined	• ***Count Net*** study which balances gross renewable sector gains with:
	  o The losses that result from the crowding out of cheaper forms of conventional energy generation; and
	  o The drain on economic activity precipitated by higher electricity prices, including a loss of consumer spending power, and lower total investments of industrial energy consumers.
	• Also notes that:
	  o New green jobs are often filled by workers who were previously employed, leading to a further overestimate of gross jobs effects;
	  o Energy security benefits of solar PV are undermined by reliance of imported fossil fuel sources to meet technological demand; and
	  o Technological innovation is stifled via a subsidy that compensates an energy technology for its lack of competitiveness.
	• Assesses real net present cost of solar subsidies, based on the volume of solar generation, the FIT, and conventional electricity prices.
	• Specific net cost per kWh = difference between solar FIT and market prices at the power exchange.

Model Assumptions	• Utility central station generation costs of 2-7 cents/kWh • Utilities obliged to accept delivery of power into their own grids from independent renewable producers • Solar-specific FIT of 50.62 cents/kWh paid by utilities in 2000 falling to 43.01 cents/kWh in 2009. • If solar subsidization ended in 2009, electricity consumers would still face charges until 2029. • Assumes 2% annual inflation. • Cost estimates for PV modules installed 2000-2008 are based on an overall solar electricity production of 96 billion kWh during 20 years of subsidization.
Solar Growth Projection Assumptions	• Germany had 5,311 MW installed PV capacity in 2008.
Effects Scaled per Year (2015 $)	• Net cost promoting Solar PV per MW installed: $3.18 million, 2000-2008 (2015 $).[15]

[15] €2.2 million (2007 €) converted to US$ at a rate of US$1: €0.7687.

Title	**Building the Green Economy: Employment Effects of Green Energy Investments for Ontario**
Author(s)	**Pollin & Garrett-Peltier, 2009**
Background	University of Massachusetts-Amherst study sponsored by the Green Energy Act Alliance, Blue Green Canada, and World Wildlife Fund (Canada).
Objective(s)	• Considers the employment benefits of two Ontario green investment agendas: o Baseline Integrated Power System Plan (IPSP): $18.6 BN investment over 10 years in conservation and demand management, hydroelectric, on-shore wind, bioenergy, waste energy recycling and solar power; and o Expanded Green Energy Act Alliance (GEAA): $47.1 BN investment over 10 years in IPSP's 6 areas plus off-shore wind and smart grid electrical transmission system.
Geography	Ontario, Canada
Time Period	10 years
Modeling Tool	• Author-modified provincial I-O tables for Ontario, combined with national I-O tables for Canada to construct wind, solar, biomass and building retrofitting as industries in their own right. • Also uses U.S. data (BLS 2007 Occupational Employment Survey) to determine which occupations are likely to be in high demand for each of the 8 renewable energy areas considered.
Type of Effects Examined	• ***Count Gross*** study, addressing employment. • No comparison is made with alternative, non-green investments. • Neither do they consider if a green investment program is the most effective way to generate jobs in the region.
Model Assumptions	• Uses three factors to establish relative employment effects of alternative green investments: o Labor intensity of spending – that is amount spent on workers rather than land, energy, or materials; o Local content of spending; and o Wage rates. • 3% of baseline IPSP spending is allocated on an annual basis to solar. • 16% of expanded GEAA spending is allocated on an annual basis to solar.
Solar Growth Projection Assumptions	• 88 MW of solar energy supplied over 10 years for baseline IPSP. • 1,738 MW of solar energy supplied over 10 years for expanded GEAA.
Effects Scaled per Year	• IPSP: 89.7 gross job years per MW installed. • GEAA: 68.7 gross job years per MW installed.

Title	**Study of the Effects on Employment of Public Aid to Renewable Energy Sources**
Author(s)	**Alvarez, Jara, Julian and Bielsa, March 2009**
Background	Universidad Rey Juan Carlos study part-funded by DG TREN (Energy & Transport) of the European Commission.
Objective(s)	To demonstrate the extent to which government support for green jobs in Europe has been economically counterproductive.
Geography	Spain
Time Period	2000-2008
Modeling Tool	Non-Applicable
Type of Effects Examined	• ***Count Net*** study. • Compares average amount of subsidized investment needed to create a solar job with the average amount of capital needed for a job in the private sector. • Also compares the average annual productivity that the solar job subsidy would have contributed to the economy had it not been consumed in public financing, with the average productivity of labor in the private sector that allows them to keep their job.
Model Assumptions	• The total subsidy to PV, wind, and hydro since 2000 is \$36 billion. • No additional solar plants have been constructed since December 2008. • \$12.1 billion has been committed for PV generation, 2000-2008.
Solar Growth Projection Assumptions	• Assumes that Spain has installed 2,934 MW solar PV by 2008.
Effects Scaled per Year	• For every renewable energy job financed by government, on average 2.2 jobs will be lost in the private sector. • However, for every solar MW installed, 8.99 private jobs are destroyed as a result of "green jobs" mandates, subsidies and related regimes.

4.0 Economic Impact Analyses – Magnitudes & Preferred Modeling Methods

Gross (positive impact only) studies clearly produce higher estimates of the economic impacts of solar enhancements than net studies, as demonstrated by the studies reviewed in Section 3. It is also important to note that gross studies are uniformly positive, while net studies are generally negative in terms of divined economic impact.

The principal effect of using a partial model approach rather than a count approach, or using a general (macroeconomic) modeling approach rather than a partial approach, is to reinforce the magnitude of the divined economic impacts. Thus, using a general (macroeconomic) model approach yields the most significant gross and negative studies.

Figure 3 summarizes the magnitude of impacts by type of economic impact study, based on the studies critiqued in Section 3.

Counts usually quantify the number of jobs. The Ontario ***Count Gross*** analysis reviewed in Section 3 estimated 68.7 to 89.7 gross (direct) job years are generated for every MW of wind and solar energy installed, which averages out at 69.74 for both renewable programs.

The Spanish ***Count Net*** analysis reviewed in Section 3 estimates that 8.99 private jobs are lost through "green jobs" mandates, subsidies and related regimes, for every 1 MW of solar installed.

Frondel et al. do not provide actual job counts for their German ***Count Net*** analysis. They simply conclude that "...any result other than a negative net balance of the German PV promotion would be surprising" (p. 17), based on a per capita subsidy of $257,400 in 2008, the EEG's crowding out effects, negative income effects and the unprecedented competition from cheaper Asian imports.[16]

Partial model estimates extend beyond a count to additionally estimate Gross State Product (GSP). The ***Partial Gross*** models reviewed in Section 3 estimated 5 to 73.5 gross job year gains per MW installed, and

[16] Frondel et al. report that in 2006 and 2007, almost half of Germany's PV demand was covered by imports, most notably from Japan and China.

a GSP gain of $106,800 to $1.24 million per MW installed per year (2015 $). The AECOM study appears to be something of an outlier, as the gross job year estimate for the three other studies ranges from 5 to 24.9 job years per solar MW installed. Four of the studies in this section estimate GSP contributions of $106,800 to $176,354 GSP per MW per year (all 2015 $). The two exceptions, estimating significantly higher GSP contributions per MW per year are VSI (2011) in Nevada, and the AECOM study.

NYSERDA's ***Partial Net*** model estimates a 700 economy-wide net gain in job years for their low case scenario, but a 750-2,500 economy-wide net loss for job years for their base and high case scenarios. Similarly NYSERDA estimate a $15,760 GSP net gain per MW installed per year for their low case scenarios, compared to net losses of $16,930 to $58,386 per MW installed per year for their base and high case scenarios (all 2015 $). Treyz et al. only present graphs, rather than actual data, which appear to show a net negative loss in both job years and GDP, 2011-2035.

Figure 3: Magnitude of Economic Impacts

	Counts	Partial Models	General Models
Gross ***Only positive or negative impacts***	• 70 gross job years per MW	• Range of 5 to 73.5 gross job years per MW. • Range of $106,830 to $1.24 million GSP per MW per year.	• $7,198 total production per MW installed per year for parabolic trough installations.[17] • $4,265 total production per MW installed per year for solar tower installations.[18]
Net ***Both positive and negative impacts***	• -8.99 private jobs per MW per year	• Range of +750 to -2,500 net job years per MW, dependent on the scenario. • Range of +$15,862 to -$58,386 GSP per MW installed per year, dependent on the scenario.	

[17] This is based on the PASENER target, 80% of which would be met by parabolic trough.
[18] This is based on the PASENER target, 20% of which would be met by solar tower.

The ***General Gross*** model reviewed in Section 3 offers two solar-technology dependent estimates. These are a total gross productive increase of $7,075 per MW installed per year for parabolic trough; and $4,192 per MW installed per year for solar tower.[19]

Based on the 6-way matrix of economic impact studies initially presented in Section 2, the implementation of a ***General Net*** analysis of solar deployment in the APS service territory, 2016-2035 is the best methodological approach for the current study. However, to the research team's knowledge, a CGE model of this nature currently does not exist for the State of Arizona; and it would be cost prohibitive to test and develop a CGE model for the State of Arizona in a short time frame. As a result, the current study implements a ***Partial Net*** analysis of solar deployment in the APS service territory, 2016-2035, presented in Sections 5 - 8. Seidman expects the results presented in the subsequent Sections to be directionally correct, but possibly understated, compared to a ***General Net*** (CGE) approach.

[19] This uses an IRS 2013 dollar-euro annual currency exchange rate of US$1: €0.783. Source: IRS (2014), downloaded at www.irs.gov/Individuals/International-Taxpayers/Yearly-Average-Currency-Exchange-Rates. Value is then converted into 2015 $ using the Bureau of Labor Statistics CPI Inflation Calculator.

5.0 Economic Impact of Net Metering – Scenarios, Assumptions and Method

5.1. Scenarios and Assumptions

Three distributed (rooftop) solar deployment scenarios in the APS service territory are assessed for the study period 2016-2035, including the legacy effects of each scenario throughout the (assumed) 30 year economic life of the solar systems.[20] The solar deployment scenarios assessed for APS are:

- A low case scenario, which assumes 1,300 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 150,000 accounts;
- An expected or medium case scenario, which assumes 5,000 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 690,000 accounts; and
- A high case scenario, which assumes 7,600 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 1,050,000 accounts.

Distributed solar deployment is assumed to take place throughout the period of study in each scenario – that is, up to and including 2035.

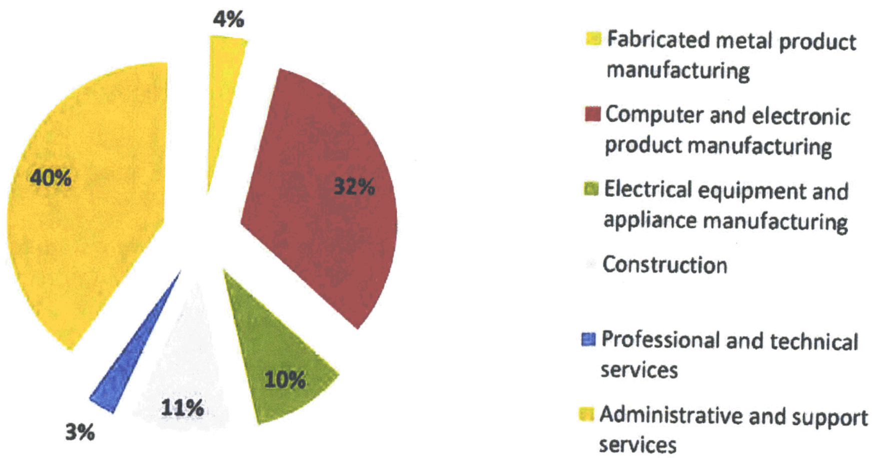
Approximately 86% of the solar installations are assumed to occur in Maricopa County, 5% in Pinal County, and 9% in Yuma County in each scenario.

The capital costs and financing implications of each solar deployment scenario is determined by examining the level of distributed generation as forecast by APS using generic assumptions about the costs of standard DG solar systems and financing parameters. NREL's JEDI model for solar installations is used to

[20] Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

distribute the capital costs of the solar installations throughout the supply chain in the State of Arizona.[21] Figure 4 summarizes the breakdown of the JEDI model's solar system costs used in this analysis. This is based on national industry averages, and may not match Arizona's experience exactly, but is nevertheless widely accepted as a reasonable approximation. Administrative and support services account for an estimated 40% of solar system costs. This probably includes general administrative costs associated with state government permitting and federal rebates, and also local administrative costs in the solar industry.

Figure 4: JEDI Model Exogenous Final Demand Categories



Source: Authors' Calculations

APS has also supplied Seidman with an estimate of the financial impact of each solar deployment scenario on the utility's operating cash flow, future central station generation investments, and electricity retail rates. Approximately 70% of the deferred or cancelled central station generation investments occurring under the three distributed solar scenarios are assumed to occur in Maricopa County, with the balance in Pinal County.

The investment changes included in the economic impact model are:

- The annual installed costs of distributed solar capacity, 2016-2035; and

[21] NREL's JEDI models are an open-source, Excel-based, user-friendly tools that estimate the economic impacts of constructing and operating power generation and biofuel plants at the local and state levels. To find out more about the JEDI models, see http://www.nrel.gov/analysis/jedi/about_jedi.html

- APS' deferred or avoided central station generation investments, 2016-2035.

The long-term legacy costs included in the economic impact model are:

- The customer leasing costs of distributed solar installations, 2016-2060;[22] and
- Consumer electricity rate savings, 2016-2060, from the study period's deferred or avoided central station generation.

The timeframe of three of these elements extends beyond the last year of deployment (2035). This is because there are legacy effects associated with the deployment of distributed solar. For example, any customer installing a distributed solar PV system will have to meet the financial costs of that system for up to 30 years after the system has been installed on their roof. A utility is also required to recoup any investment in central station generation investments via retail electricity rates over the lifetime of that investment – again, usually 30 years. The legacy effects are therefore accounted for in the analysis.

The modelling elements are discussed in more detail in Section 5.2.

5.2. Study Method

Given the absence of a CGE model for the State of Arizona, Section 4 recommended the implementation of a ***Partial Net*** analysis of solar deployment in the APS service territory, 2016-2035. As a result, this study makes use of an Arizona-specific version of the REMI regional forecasting model, updated at the Seidman Research Institute, to produce partial net estimates of the impact on the Arizona economy of changes in the economic environment in the state.

REMI is especially useful when examining the economic impact associated with the launch or expansion of a new program, such as NEM, in a particular region, state or country. Through its dynamic modeling, REMI takes account of variations in the economic impact of a program as it moves from the establishment

[22] Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

to operations phase, and also shows how estimates can vary through time. These estimated impacts are the difference between the baseline economy and the baseline economy augmented with the level of solar deployment assumed under each scenario. As a result, the analysis measures the Arizona economy up to 2035 *with* and *without* the existence of the new solar rooftop program.

The use of a county level model also enables a more detailed disaggregation of results to occur, estimating the "leakage" of economic impacts into other counties in Arizona.

Due to its overall flexibility, REMI allows for the examination of a whole host of different scenarios – different businesses and/or different construction and operations phases – while simultaneously providing estimates that are consistent across projects.

The method for estimating the economic impact involves four fundamental steps:

1. **Prepare a baseline forecast for the state and county economies:** This Business As Usual (BAU) case forecasts the future path of state and county economies based on a combination of an extrapolation of historic economic conditions and an exogenous forecast of relevant national economic variables.
2. **Develop a program or policy scenario:** This scenario describes the *direct* impacts that each distributed solar deployment scenario could generate in APS' service territory.
3. **Compare the baseline and policy scenario forecasts.**
4. **Produce the "delta" results**: Differences between the future values of each variable in the forecast results estimate the magnitude that each distributed solar deployment scenario could have on the state or county economies, relative to the baseline.

The baseline or counterfactual scenario employed in this study assumes that there are no additions to the current stock of distributed solar installations over the period 2016-2035 in APS' service territory. One consequence of this counterfactual scenario is that APS would need to add to both its central generation and transmission capacity, to cope with the increased load within its territory over the period. To cover the capital costs of the enhanced capacity and all subsequent operations and maintenance costs, APS would typically need to increase utility revenues over a 30-year period from the date of each investment. In isolation, this would manifest as a reduction in consumer spending, because utility customers would collectively need to pay more for these new investments, and is also accounted for in the current study, up to and including 2060. In reality, some of this increased revenue will be provided by population growth which is creating the additional demand for new generation, and some will be offset by lower revenues for depreciating existing investments over time.

5.3. Solar Deployment Scenarios

Three distributed solar deployment scenarios are analyzed in this study. To represent the effects of increased penetrations of distributed solar, three key changes are included in the current study for the 2016-2035 time horizon. These are:

- The capital costs expended on rooftop solar systems purchased or leased by distributed generation customers, which are assumed to yield 20 years of construction-based benefits on the Arizona economy;
- The financial payments made by utility customers for leased solar systems for the economic life of their assets. This represents a reduction in spending on other goods and services and, as such, a likely reduction in economic activity in Arizona; and
- The reduction in revenue requirement for APS as a result of decreased net investment in centrally generated power. This represents a loss to the Arizona economy due to the reduction in central station generation construction and employment, offset by savings on fuel, O&M and financing costs over time.

Each scenario is modeled over a 20-year timeframe, starting in 2016 and ending in 2035, to estimate the employment, gross state product (GSP), and real disposable personal income (RDPI) for the State of Arizona and Maricopa County. However, there are also legacy effects associated with solar deployment and the deferral or cancellation of central station generation investments, which occur in the years immediately following an installation and last for the economic life of the solar installations. These legacy effects are therefore also included in the cumulative 2016-2035 estimate provided for each assessed economic measure, expressed in 2015 dollars (2015 $).[23]

[23] The legacy effects for any 2035 distributed solar installations should last until 2065, to reflect the economic life of the system. The current REMI model is unable to provide estimates after 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

6.0 Simulation Results: Low Distributed Solar Deployment Scenario

The low case scenario assumes that over $1.5 billion is invested in new distributed solar installations by 112,000 customers between 2016 and 2035, and the net deferral or cancellation of $85.5 million central station generation investments up to and including 2065 (all nominal $).[24]

Table 2 estimates the total employment impacts of the low case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers. They include employees, sole proprietors and active partners, but exclude unpaid family workers and volunteers. The data is expressed in job years. The label "job year" is important and should not be simplified or abbreviated to "job". A "job year" is defined as one person having a full-time job for exactly one year. This means, for example, that one employee holding the same position at the same organization throughout 2016-2035 will account for 20 job years, but also only represent 1 job.

Table 2: Total Private Non-Farm Employment Impacts 2016-2035 (including Legacy Effects to 2060)

Geography	Job Years[25]
State of Arizona	-16,595
Maricopa County	*-15,685*

Source: Authors' Calculations

Table 2 suggests that the low case distributed solar scenario could have a negative employment impact of 16,595 full-time (or equivalent) job years in the State of Arizona throughout the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.[26]

In Maricopa County, there is a negative employment impact of 15,685 job years for the study period as a whole (including subsequent legacy effects).

[24] This simply reflects a deferral from the base case.
[25] A job year is equivalent to one person having a full-time job for exactly one year.
[26] The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

Table 3 summarizes the industry sectors impacted the most by the low case distributed solar scenario.

Table 3: Statewide Employment Impacts by Industry Sector (Job Years)[27]

Sector	Total Job Years, 2016-2060[28]
Forestry, Fishing, and Related Activities	-2
Mining	-639
Utilities	-2,025
Construction	-2,549
Manufacturing	-385
Wholesale Trade	-548
Retail Trade	-3,102
Transportation and Warehousing	-514
Information	-203
Finance and Insurance	-845
Real Estate and Rental and Leasing	-998
Professional and Technical Services	-3,505
Management of Companies and Enterprises	-89
Administrative and Support Services	5,447
Educational Services	-440
Health Care and Social Assistance	-3,210
Arts, Entertainment, and Recreation	-406
Accommodation and Food Services	-1,348
Other Services, except Public Administration	-1,237
Total Net Change in Job Years	**-16,595**
Total Number of Job Years Lost in Non-Solar Industry Sectors[29]	**22,042**

Source: Authors' Calculations

The table suggests that administrative and support services could benefit from the low case distributed solar scenario in terms of employment created. However, all other sectors are estimated to experience job losses, resulting in the total net estimate of 16,595 job years lost statewide. The administrative gain probably originates to a large extent from the permitting of solar installations, and also business support functions within the solar industry. The sectors estimated to experience the biggest job losses (expressed

[27] A job year is equivalent to one person having a full-time job for exactly one year.
[28] Total job years may not tally due to rounding-up.
[29] This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

in cumulative job years) during the study period in rank order are professional; scientific and technical services; health care and social assistance; retail trade; the construction industry; and utilities.

Table 4 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the low case distributed solar scenario for the period 2016-2035.

Table 4: Total Gross State Product (GSP) and Real Disposable Personal Income Impacts (RDPI) 2016-2035 (including Legacy Effects to 2060)

Geography	Gross State Product Millions (2015 $)	Real Disposable Personal Income Millions (2015 $)
State of Arizona	**-$4,806.6**	**-$1,787.3**
Maricopa County	***-$4,491.8***	***-$1,862.4***

Source: Authors' Calculations

Table 4 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by over $4.8 billion (2015 $) in the State of Arizona. This includes an estimated $4.5 billion GSP lost in Maricopa County (2015 $).

Table 4 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by almost $1.8 billion (2015 $) in the State of Arizona. This includes an estimated fall in RDPI of over $1.86 billion in Maricopa County (2015 $).[30]

The employment, GSP, and RDPI losses associated with the low distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the relevant time period (which extends beyond 2035) is greater than the amount which would have been paid had they all instead continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the low distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

[30] Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

7.0 Simulation Results: Expected Distributed Solar Deployment Scenario

The expected or medium case scenario assumes that approximately $8.9 billion in total is invested by 650,000 customers in distributed solar installations between 2016 and 2035, and the deferral or cancellation of $194 million central station generation investments (all nominal $).[31]

Table 5 estimates the total employment impacts of the expected or medium case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers; and the data is again expressed in job years.

Table 5: Total Private Non-Farm Employment Impacts 2016-2035 (including Legacy Effects to 2060)

Geography	Job Years[32]
State of Arizona	-76,308
Maricopa County	*-71,344*

Source: Authors' Calculations

Table 5 suggests that the expected or medium case distributed solar scenario would have a negative employment impact of 76,308 full-time (or equivalent) job years in the State of Arizona for the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.[33]

In Maricopa County, there is a negative employment impact of 71,344 job years throughout the study period (including subsequent legacy effects).

Table 6 summarizes the industry sectors impacted the most by the expected or medium case distributed solar scenario.

[31] This simply reflects a deferral from the base case.
[32] A job year is equivalent to one person having a full-time job for exactly one year.
[33] The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

Table 6: Statewide Employment Impacts by Industry Sector (Job Years)[34]

Sector	Total Job Years, 2016-2060[35]
Forestry, Fishing, and Related Activities	-18
Mining	-2,563
Utilities	-7,709
Construction	-11,098
Manufacturing	-1,504
Wholesale Trade	-2,691
Retail Trade	-15,762
Transportation and Warehousing	-2,472
Information	-943
Finance and Insurance	-4,558
Real Estate and Rental and Leasing	-4,948
Professional and Technical Services	-14,366
Management of Companies and Enterprises	-361
Administrative and Support Services	29,025
Educational Services	-2,336
Health Care and Social Assistance	-18,026
Arts, Entertainment, and Recreation	-2,231
Accommodation and Food Services	-6,886
Other Services, except Public Administration	-6,860
Total Net Change in Job Years	**-76,308**
Total Number of Job Years Lost in Non-Solar Industry Sectors[36]	**105,333**

Source: Authors' Calculations

The table again suggests that administrative and support services alone could benefit from the expected or medium case distributed solar scenario in terms of job years' employment created. However, all other sectors are estimated to experience job losses, resulting in the total net estimate of 76,308 job years lost statewide. The administrative gain again probably originates to a large extent from the permitting of solar installations and business functions within the solar industry. The sectors estimated to experience the biggest job losses (expressed in cumulative job years) during the study period in rank order are health care and social assistance; retail trade; professional; scientific and technical services; the construction industry; and utilities.

[34] A job year is equivalent to one person having a full-time job for exactly one year.
[35] Total job years may not tally due to rounding-up.
[36] This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

Table 7 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the expected or medium case distributed solar scenario for the period 2016-2035.

Table 7: Total Gross State Product (GSP) and Real Disposable Personal Income Impacts (RDPI) 2016-2035 (including Legacy Effects to 2060)

Geography	Gross State Product Millions (2015 $)	Real Disposable Personal Income Millions (2015 $)
State of Arizona	-$21,613.3	-$7,956.4
Maricopa County	*-$20,149.9*	*-$8,087.9*

Source: Authors' Calculations

Table 7 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by over $21.6 billion (2015 $) in the State of Arizona under the expected or medium case scenario. This includes an estimated $20.1 billion GSP lost in Maricopa County (2015 $).

Table 7 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by approximately $8 billion (2015 $) in the State of Arizona. This includes an estimated fall in RDPI of almost $8.1 billion in Maricopa County (2015 $).[37]

The employment, GSP, and RDPI losses associated with the expected distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the 2016-2060 time horizon is greater than the amount which would have been paid had they all continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the expected distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

[37] Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

8.0 Simulation Results: High Distributed Solar Deployment Scenario

The high case scenario assumes that approximately $13.4 billion is invested by approximately 1 million customers in distributed solar installations between 2016 and 2035, and the deferral or cancellation of $194 million central station generation investments (both nominal $).[38]

Table 8 estimates the total employment impacts of the high case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers; and the data is again expressed in job years.

Table 8: Total Private Non-Farm Employment Impacts 2016-2035 (including Legacy Effects to 2060)

Geography	Job Years[39]
State of Arizona	-116,558
Maricopa County	*-108,857*

Source: Authors' Calculations

Table8 suggests that the high case distributed solar scenario could have a negative employment impact of 116,558 full-time (or equivalent) job years in the State of Arizona for the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.[40]

In Maricopa County, there is a negative employment impact of 108,857 job years throughout the study period (including subsequent legacy effects).

Table 9 summarizes the industry sectors impacted the most by the high case distributed solar scenario.

[38] This simply reflects a deferral from the base case.
[39] A job year is equivalent to one person having a full-time job for exactly one year.
[40] The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

Table 9: Statewide Employment Impacts by Industry Sector (Job Years)[41]

Sector	Total Job Years, 2016-2060[42]
Forestry, Fishing, and Related Activities	-30
Mining	-3,496
Utilities	-10,632
Construction	-14,220
Manufacturing	-2,074
Wholesale Trade	-4,318
Retail Trade	-25,645
Transportation and Warehousing	-3,847
Information	-1,505
Finance and Insurance	-7,489
Real Estate and Rental and Leasing	-7,892
Professional and Technical Services	-20,701
Management of Companies and Enterprises	-538
Administrative and Support Services	45,650
Educational Services	-3,898
Health Care and Social Assistance	-29,486
Arts, Entertainment, and Recreation	-3,668
Accommodation and Food Services	-11,364
Other Services, except Public Administration	-11,405
Total Net Change in Job Years	**-116,558**
Total Number of Job Years Lost in Non-Solar Industry Sectors[43]	**162,208**

Source: Authors' Calculations

Consistent with the previous two scenarios, the table suggests that administrative and support services could benefit alone from the high case distributed solar scenario in terms of job years employment created. The administrative gain again probably originates to a large extent from the permitting of solar installations, and also business support functions within the solar industry. All other sectors are estimated to experience job losses, resulting in the total net estimate of 116,558 job years lost statewide. The sectors estimated to experience the biggest job losses (expressed in cumulative job years) during the study period in rank order are health care and social assistance; retail trade; professional; scientific and technical services; the construction industry; and other services (excluding public administration).

[41] A job year is equivalent to one person having a full-time job for exactly one year.
[42] Total job years may not tally due to rounding-up.
[43] This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

Table 10 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the high case distributed solar scenario for the period 2016-2035.

Table 10: Total Gross State Product (GSP) Impacts 2016-2035 (including Legacy Effects to 2060)

Geography	Gross State Product Millions (2015 $)	Real Disposable Personal Income Millions (2015 $)
State of Arizona	-$31,454.4	-$11,901.4
Maricopa County	*-$29,346.7*	*-$12,091.2*

Source: Authors' Calculations

Table 10 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by $31.5 billion (2015 $) in the State of Arizona under the high case scenario. This includes an estimated $29.3 billion GSP lost in Maricopa County (all 2015 $).

Table 10 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by $11.9 billion (2015 $) in the State of Arizona. This includes an estimated fall in RDPI of almost $12.1 billion in Maricopa County (2015 $).[44]

The employment, GSP, and RDPI losses associated with the high distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the 2016-2060 time horizon is greater than the amount which would have been paid had they all continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the high distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

[44] Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

9.0 Conclusions

The goal of this study is to assess the impact of three distributed solar deployment scenarios in the APS service territory on economic activity in the State of Arizona and Maricopa County. The results of the analysis are influenced to an extent by the choice of economic impact model implemented.

Economic impact analyses can generally be classified in one of 6 ways, represented in Figure 5.

Figure 5: Seidman's 3 x 2 Classification of Economic Impact Models

COUNT GROSS	PARTIAL GROSS	GENERAL GROSS
COUNT NET	PARTIAL NET	GENERAL NET

Gross studies only consider the direct positive impacts of increased economic activity in a specific sector, whereas ***Net*** studies represent a more thorough form of economic modeling as they also account for the trade-offs in the economy which result from incentivizing one specific sector,

Counts are usually survey-based or theoretical capacity installation quantifications of the number of direct employees within a specific economic sector, which can extend to that sector's entire supply chain.

Partial models consider the wider effects of levels of activity in a specific economic sector, including the indirect and induced effects of the direct sectoral change. Frequently assessed via input-output models such as IMPLAN and REMI, partial models do not consider the feedback effects of changed levels of activity in a specific sector, such as the effect of large solar projects on wages in the labor market.

General models offer the most comprehensive economy-wide analysis, taking into account all of the economic interconnections and feedback effects. Of the fourteen contemporary solar economic impact studies critiqued by Seidman, only one uses a general equilibrium model. This is Cansino, Cardenete, Gonzalez and Pablo-Romero's (2013) study of Andalusia. However, this is a gross, rather than net analysis, because the authors combine renewables and non-renewables as a single sector, thereby preventing any substitution between conventional and renewable forms of generation, and effectively only allowing for positive direct demand shocks in their modeling.

The principal effect of using a ***Partial*** model approach rather than a ***Count*** approach, or using a ***General*** modeling approach rather than a ***Partial*** approach, is *generally* to reinforce the magnitude of the divined economic impacts. Thus, using a ***General*** model approach yields the most significant ***Gross*** and ***Net*** impacts.

However, to the research team's knowledge, a CGE model currently does not exist for the State of Arizona; and it would be cost prohibitive to test and develop a CGE model for the State of Arizona in a short time frame.

Seidman has therefore implemented a ***Partial Net*** REMI analysis of solar deployment in the APS service territory, 2016-2035, for the current study. This is the next best alternative from a methodological standpoint; and it is consistent, for example, with the approach taken by Berkman, Lagos and Weiss (2014), NYSERDA (2012), and Treyz et al. (2011), critiqued in Section 3. Figure 6 positions Seidman's approach relative to the fourteen critiqued studies

Figure 6: Classification of Seidman's 2016 Approach for APS Relative to Fourteen Contemporary Economic Impact of Solar/Renewables Studies

	Counts	Partial Models	General Models
Gross ***Only positive or negative impacts***	• Pollin and Garrett-Peltier, 2009 • ETIC, 2016	• AECOM, 2011 • Loomis, Jo & Alderman ,2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al. , 2014	• Cansino et al. 2013
Net ***Both positive and negative impacts***	• Alvarez et al., 2009 • Frondel et al., 2009	• NYSERDA, 2012 • Treyz et al., 2011 • Berkman et al., 2014 • **SEIDMAN 2016**	

The economic impacts of all three distributed solar deployment scenarios are assessed in terms of private non-farm employment, gross state product, and real disposable personal income.

The study clearly demonstrates that increased adoption of distributed solar generation represents a *loss* to the Arizona economy as a whole in all three scenarios. This is because the overall cost of provision of electricity to the State of Arizona will rise when referenced against a base case where electricity continues to be provided by central station generation.

If the low case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

- 16,595 job years private non-farm employment;
- Over $4.8 billion gross state product (2015 $); and
- $1.8 billion real disposable personal income (2015 $).

This takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.[45]

If the expected or medium case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

- 76,308 job years private non-farm employment;
- Over $21.6 billion gross state product (2015 $); and
- Almost $8 billion real disposable personal income (2015 $).

This also takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations, to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.

If the high case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

[45] The legacy effects of any 2035 distributed solar installation or deferred central station generation will continue until 2065. However, the REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

- 116,558 job years private non-farm employment;
- Approximately $31.5 billion gross state product (2015 $); and
- $11.9 billion real disposable personal income (2015 $).

This again takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations, to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.

The implications of these findings are potentially far-reaching, as they challenge a sometimes expressed claim that an aggressive distributed solar initiative will have a significant positive impact on the state and county economies in the State of Arizona.

In short, and wholly based on the financial implications of solar installations from a customer, utility and supplier perspective, this study estimates that any benefits emanating from the three distributed solar deployment scenarios are at best temporary and only coincident with the timing of those solar installations. This is because the lasting legacy effects of each distributed solar scenario, which reflect the economic life of the installed systems and deferred central station generation, are negative. That is, in all three scenarios, the total amount of money paid by distributed generation and central station generation electricity consumers over the relevant time period (2016-2060) is greater than the amount which would have been paid had they all alternatively continued to draw electricity from the utility's central grid. In each distributed solar scenario, electricity consumers as a whole are being asked to pay more for the same amount of electricity consumed, and therefore have less money to spend in other parts of the economy.

Thus, when considered in the round from a purely financial perspective, the economic impact of all three potential solar deployed scenarios in the APS service territory are estimated to have a detrimental effect on both the State of Arizona and Maricopa County economies, all other things being equal.

Appendix

A.1. The REMI Model

REMI is an economic-demographic forecasting and simulation model developed by Regional Economic Models, Inc. REMI is designed to forecast the impact of public policies and external events on an economy and its population. The REMI model is recognized by the business and academic community as the leading regional forecast/simulation tool available.

Unlike most other regional economic impact models, REMI is a dynamic model that produces integrated multiyear forecasts and accounts for dynamic feedbacks among its economic and demographic variables. The REMI model is also an "open" model in that it explicitly accounts for trade and migration flows in and out of the state. A complete explanation of the model and discussion of the empirical estimation of the parameters/equations can be found at www.remi.com.

The operation of the REMI model has been developed to facilitate the simulation of policy changes, such as a tax increase for example, or many other types of events – anything from the opening of a new business to closure of a military base to a natural disaster. The model's construction includes a large set of policy variables that are under the control of the model's operators. To simulate the impact of a policy change or other event, a change in one or more of the policy variables is entered into the model and a new forecast is generated. The REMI model then automatically produces a detailed set of simulation results showing the differences in the values of each economic variable between the control and the alternative forecast.

The specific REMI model used for this analysis was Policy Insight Model Version PI^{+} version 1.7.2 of the Arizona economy (at the county level) leased from Regional Economic Models Inc. by a consortium of State agencies, including Arizona State University, for economic forecasting and policy analysis.

A.2. Effects Not Incorporated into the Analysis

No major financial impacts were left out.

Glossary

Gross State Product (GSP): The dollar value of all goods and services produced in Arizona for final demand/consumption.

Job Year: A job year is equivalent to one person having a full-time job for exactly one year.

Real Disposable Personal Income: The household income that is available to be spent after tax payments. Technically speaking, real disposable personal income is the sum of wage and salary disbursements, supplements to wages and salaries, proprietors' income, rental income of persons, personal dividend income, personal interest income, and personal current transfer receipts, less personal taxes and contributions for government social insurance.

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REBUTTAL TESTIMONY OF ASHLEY C. BROWN

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

EXHIBIT

APS-9

ADMITTED

April 7, 2016

APS EXHIBIT 9

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REBUTTAL TESTIMONY OF ASHLEY C. BROWN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Ashley C. Brown. I am Executive Director of the Harvard Electricity Policy Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a "think tank" on electricity policy, including pricing, market rules, regulation, environmental and social considerations. HEPG, as an institution, never takes a position on policy matters, so my testimony today represents solely my opinion, and not that of the HEPG or any other organization with which I may be affiliated.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this docket.

Q. ON WHOSE BEHALF DO YOU OFFER TESTIMONY?

A. On behalf of the Arizona Public Service Company.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut direct testimony provided by Briana Kobor, witness for Vote Solar, and Thomas Beach, witness for The Alliance for Solar Choice, in this matter.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A. My testimony is composed of two parts. The first shows that a "value of solar" approach to pricing rooftop solar is not appropriate, and Mr. Beach and Ms. Kobor do not offer a rationale for taking such an approach to pricing rooftop solar. The second part, offered on the assumption that the Commission wants to examine how a "value" approach to rooftop solar might work, is an analysis of why the methods and considerations suggested by Mr. Beach and Ms. Kobor are inappropriate, incomplete, and, in many cases, simply inaccurate.

II. HOW THE TESTIMONY OF MS. KOBOR AND MR. BEACH DEMONSTRATES THE PROBLEMS WITH A VALUE OF SOLAR ANALYSIS.

Q. PLEASE DISCUSS THE ARBITRARINESS OF MR. BEACH AND MS. KOBOR'S PROPOSED VALUE OF SOLAR ANALYSIS.

A. A "value of solar" analysis is inherently too uncertain and arbitrary to be a useful guide to set public policy. Ms. Kobor's proposal for a value of solar methodology proves my point. It's revealing to gather together in one place a list of all of the assumptions, estimates, forecasts, and approximations Ms. Kobor suggests would need to be made during the course of her testimony on value of solar:

- Forecast of future utility rates going out twenty to thirty years, by customer class, assessed for reasonableness by "interested parties";[1]
- Impact analyses of any expected "significant changes in rate design," with a scenario analysis of potential rate design structures;[2]
- Hosting capacity analyses;[3]
- "Inputs…for a detailed marginal cost study valuing transmission and distribution capacity";[4]

[1] Direct Testimony of Brianna Kobor, p. 27.
[2] *Id.* at 27.
[3] *Id.* at 22:9.
[4] *Id.* at 22:9-10.

- A "chosen" discount rate;[5]
- An estimate of expected DG penetration levels;[6]
- A decision about what time period will be looked at for estimating DG penetration (Ms. Kobor suggests one to three years, which is in tension with her emphasis in other cases on twenty or thirty year projections);[7]
- A value for incremental DG capacity additions;[8]
- Utility data on current price paid to customers for DG exports by customer class;[9]
- Hosting capacity analyses specific to each utility system (as suggested by Mr. Volkmann and endorsed by Ms. Kobor);[10]
- An estimate of "the cost to produce the energy that would be offset by additional DG exports," reflecting differences depending on "the individual utility and the timing and seasonality of DG exports." Ms. Kobor recommends that "assumptions" can be developed about "the marginal generator that would serve various portions of the load expected to be served by additional DG exports," based on "data on the current export profile of [utility] NEM customers";[11]
- Avoided cost of energy from each of the marginal generators identified through the assumptions above. This includes estimates (over twenty or thirty years, presumably) of natural gas prices, heat rates, and "variable costs of operations and maintenance";[12]
- A projection of future prices of natural gas;[13]
- Extrapolated longer-term values for natural gas "based on publicly available forecasts";[14]
- Futures data on basis swaps prices;[15]
- Estimated costs to bring gas to generators;[16]

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[5] *Id.* at 23:8.
[6] *Id.* at 24.
[7] *Id.* at 24:16-19.
[8] *Id.* at 25.
[9] *Id.* at 27.
[10] *Id.* at 11; *see* Direct Testimony of Curt Volkmann 6:18-20.
[11] Direct Testimony of Brianna Kobor 28:7-14.
[12] *Id.* at 28:18-19.
[13] *Id.* at 28.
[14] *Id.* at 28:25.
[15] *Id.* at 28-29.
[16] *Id.* at 29.

- "sensitivity analysis based on higher- and lower-than projected natural gas prices";[17]
- An "assumption" about heat rate, "specific to the type of plant"[18] based on:
  - Expected average heat rate;[19]
  - Long-term heat rate degradation that "may occur";[20] and,
  - And "a reliable estimate of variable O&M...forecasted over the period of the analysis."[21] (20-30 years, that is);
- "marginal line losses expected during the periods of DG exports"[22] (average line loss figures will not do);
- "...assumptions must be made regarding the generation capacity additions that would be needed but for the additional DG export capacity";[23]
- New generator capital costs, to best estimated by "developing assumptions for":
  - capital costs;[24]
  - fixed O&M;[25] and
  - gen-tie transmission costs;[26]
- "level of DG export capacity that is expected to contribute to the system peak";[27]
- "an assessment of the effective load carrying capacity," which will require the analyst "to evaluate the expected technology of future DG additions";[28]
- The analysis Mr. Volkmann recommends about transmission capacity and distribution capacity savings;[29]
- A value for the social cost of carbon;[30]

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[17] *Id.* at 29:4.
[18] *Id.* at 29:7.
[19] *Id.* at 29.
[20] *Id.* at 29:9.
[21] *Id.* at 29:9-11.
[22] *Id.* at 29:17-18.
[23] *Id.* at 31:1-2.
[24] *Id.* at 31.
[25] *Id.*
[26] *Id.*
[27] *Id.* at 31:7.
[28] *Id.* at 31:8-9, 15.
[29] *Id.* at 32.
[30] *Id.* at 34.

- EPA estimate of social cost of major pollutants, "netted against the level of compliance costs embedded in avoided energy costs";[31]
- A value for avoided water consumption;[32] and
- An assessment of "the potential multiplier affect associated with DG-related jobs."[33]

All of this is to be provided for twenty or thirty years. What could possibly go wrong?

Ms. Kobor herself downplays the difficulty of the task she is setting for regulators and analysts, sometimes to (presumably unintentionally) humorous effect. After laying out a daunting list of approximations and assumptions necessary in order to value the capacity of rooftop solar ("assumptions must be made regarding the generation capacity additions that would be needed...[c]apacity costs...can be estimated by developing assumptions for capital costs, fixed O&M, and gen-tie transmission costs...the level of DG export capacity that is expected to contribute to system peak...an assessment of the effective load carrying capacity...it will be necessary to evaluate the expected technology of future DG additions."[34] Ms. Kobor goes on to write that "[w]ith these assumptions in place, calculating the generation capacity savings of DG is a relatively simple undertaking[!]"[35] Ms. Kobor's testimony in that regard calls to mind the story of the economist who, stranded on a desert island, plans his escape by assuming a boat. The analysis is only simple if you assume the hard part happens and is somehow reliable despite all the different judgments and assumptions that must be made, not to mention that it is almost inevitable that every analyst will have varying points of view on each and every one of these data points, leaving the Commission to wade through them to derive "the truth." All of this burden will be placed on the Commission despite the fact

[31] *Id.* at 34:15-16.
[32] *Id.* at 35.
[33] *Id.* at 35:18-19.
[34] *Id.* at 31:1-5.
[35] *Id.* at 31:17-18.

that cost data and market measures are readily available for use at considerably less cost and guaranteed to arrive at an outcome that is considerably more fair to consumers.

Q. DO MS. KOBOR OR MR. BEACH OFFER A JUSTIFICATION FOR FOLOWING A "VALUE OF SOLAR" APPROACH TO PRICING?

A. No. Neither witness offers any justification, or even rationale, for the idea that we should price rooftop solar based on highly subjective, often factually challenged, notions of value, while we price every other energy resource, including other renewables, based on the firm and transparently derived foundations of either cost or market. While they lay out their perspectives on how to weigh the costs and benefits of rooftop solar, they do not justify a "value" approach to pricing. Nor do they bother to try to assure the long run sustainability of rooftop solar energy, namely, finding ways to integrate solar costs and benefits as fully as possible into the generally applicable market and/or cost based pricing, thereby avoiding the controversial, highly subjective, very litigious, and historically disproven process of administratively determining "value." What they, in essence, seek is to provide a thinly veiled rationale for pricing rooftop solar at high prices that will assure rooftop solar developers high profits on a per project basis without subjecting them to the rigors of either the competitive market or cost based regulation.

In fact, the testimony provided by Mr. Beach and Ms. Kobor supports the perspective provided in my original testimony that a "value of solar" analysis is inherently arbitrary and unhelpful. It is, moreover, an approach certain to lead to unending litigation and costly administrative proceedings. When applied to a single resource in isolation, it is unclear what the purpose of the "value of solar" analysis is, other than to perpetuate monopoly, non-competitive pricing for rooftop solar that enriches developers at significant cost to all consumers, solar and non-solar alike.

Q. GIVEN THE MULTITUDE OF ASSUMPTIONS, THE CALL FOR EXTRAORDINARY PREDICTIONS OVER 30 YEARS, AND THE IMMENSE COMPLEXITY OF THE PROPOSED VALUE OF SOLAR ANALYSIS, SHOULD IT BE USED TO DETERMINE HOW MUCH CUSTOMERS PAY FOR SOLAR?

A. No. The sheer complexity of what Mr. Beach and Ms. Kobor have proposed makes it plain that the effort is simply not worthwhile. Their testimony, with all of its twists, turns, and complexities makes it plain that establishing a definitive methodology is an extraordinarily difficult task by itself, but even if we were able to derive such a product, every input that went into the analysis would be challenged and contested by any number of parties. Why would we undertake such complicated calculations, rife with so many arbitrary assumptions? Each and every element of these intricate value of solar methodologies is almost certain to be highly contested. And any conclusion would necessarily have to be revisited by the Commission and subjected to protracted and expensive administrative proceedings on a regular basis. Why do this when we have ready access to market and cost information that are certain to yield, on a transparent and relatively simple basis, all the information required to set prices? Moreover, the prices set through markets or cost based regulation will be on the same playing field that applies to all other energy resources, thus removing such risks as misallocation of capital, incoherent price signals, and costly, socially regressive cross-subsidies.

Q. ARE THE PROPOSALS OF MR. BEACH AND MS. KOBOR TO HAVE PRICES SET BY A VALUE OF SOLAR ANALYSIS HARMFUL TO CUSTOMERS?

A. Yes. By proposing an approach that insulates rooftop solar from the pressures of the market and cost based regulation, pressures that incentivize greater efficiency and productivity, Ms. Kobor and Mr. Beach would leave customers having to pay excessive prices for rooftop solar—effectively implementing (unregulated) monopoly pricing, with no long term assurance of the benefits claimed by the two witnesses. Indeed, by locking in high prices for the long term for a rather primitive product, it is inevitable that those prices will be less and less advantageous to consumers.

Q. WHY DO YOU SAY THAT ADVOCACY FOR VALUE OF SOLAR ANALYSIS IS EFFECTIVELY ADVOCACY FOR MONOPOLY PRICING FOR SOLAR?

A. Value analysis, unless carefully contextualized (an extraordinarily complicated thing to do), under the value maximization / cost minimization methodologies advanced by witnesses Ms. Kobor and Mr. Beach, inevitably pushes prices to monopoly levels. Indeed, the 2015 10K filing at the Securities and Exchange Commission by SolarCity, the nation's largest provider of rooftop solar, makes it clear that the monopoly retail price is the price they target in their business plan.[36] The "value" of a product or a service to the consumer is the full amount that consumer would be willing to pay for that product—the point at which the consumer is more or less indifferent between keeping the money and getting the product. A world in which customers were always expected to pay full "value" to them of a product would be a terrible world for consumers—one in which it would be essentially impossible for them to improve their well-being through purchases, since in every case, the would have to pay a price whose value to them is fully equal to the value of the product purchased.

Q. INSTEAD OF VALUE-BASED PRICING, HOW SHOULD ELECTRICITY BE PRICED?

A. Instead of prices reflecting the subjectively ascertained full value of products to consumers, prices should end up somewhere between the cost to produce a product and the value of that product to a customer, leaving the customer better off after buying the product than he or she would have been without the product. In order to sell the

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[36] That is a peculiar benchmark, given that the retail price is a fully bundled package of goods and services, of which energy from rooftop solar or other sources is but one component.

product, the provider must bring his price down to the level where he can meet the customer's cost benefit expectation.[37] Ms. Kobor and Mr. Beach, unlike some other advocates of value of solar approaches to pricing,[38] do not give any indication that they would support preserving a margin between the "value" of solar and what customers are actually required to pay.

Q. DO MS. KOBOR AND MR. BEACH TIE COSTS TO HOW ROOFTOP SOLAR SHOULD BE PRICED?

A. No, they do not. Nor do they appear to contemplate that a reasonable price for solar power might bear some relationship to production costs or market prices. Ms. Kobor's treatment is particularly egregious here. She completely denies that declining solar panel costs are relevant to the analysis at all, arguing that the important question is only "whether the price paid for exports is commensurate with the value received," and whether "the price paid for DG exports appropriately reflects the value of the energy provided." This would harm both customers and the development of solar.

Q. HOW WOULD DELINKING COST DECLINES AND ROOFTOP SOLAR PRICES HURT CUSTOMERS AND THE DEVELOPMENT OF SOLAR?

A. Ms. Kobor's view that declining panel costs need not be reflected in prices charged consumers is not only an extraordinarily anti-consumer sentiment worthy of a Charles Dickens novel, but is profoundly anti-solar. If costs are declining, that is good for solar, as it puts the panels within reach of more customers and will increase sales. That is exactly what markets do.

[37] This is what markets do. In incentivizing producers to lower their prices, they also provide a robust incentive to improve production processes and lower costs.

[38] *See*, Harvard Electricity Policy Group, Eighty-First Plenary Session, *Rapporteur's Summary*, Session 2 (2015), http://www.ksg.harvard.edu/hepg/Papers/2016/December%202015%20Rapporteur's%20Report%20Final.pdf.

Instead, she says it has no relevance in her construct of "value" pricing. It is also extraordinary, because it fails to recognize that the value proposition is enhanced by obtaining the same product at lower cost. Nor does she even acknowledge the fact that many of the values she assigns to rooftop solar may be obtained at lower cost by other means. She has inadvertently revealed a mindset that focuses solely on maximizing the price of solar regardless of consumer welfare and regardless of the future for the product she purports to advocate for. In essence, her view of declining costs not having to be passed on to customers removes the "value of solar" fig leaf and leaves exposed what value of solar pricing is all about to the rooftop solar industry: excessive short term profit taking by rooftop solar vendors/lessors regardless of costs to others and even to the product they sell.

Q. HOW WOULD THIS EXCESSIVE PROFIT-MAKING HARM CONSUMERS?

A. It would be extremely unfortunate for customers if the "value" of solar were taken as the methodology for appropriate pricing, even if this "value" were assessed accurately. The situation in regard to rooftop solar is even worse than this, however, because, as I argue below, if one follows the value of solar analysis approach suggested by Mr. Beach and Ms. Kobor, the "value" likely to be attributed to solar will be significantly overstated, and "value" of solar pricing would be imposed on customers without giving them the ability to choose not to pay what is asked, and without giving them the option to choose competing resources that offer better value for their money.

Q. WHAT ABOUT THE ARGUMENT THAT THESE EXCESSIVE PROFITS MUST CONTINUE OR UTILITY CUSTOMERS WILL DISCONNECT FROM THE GRID?

A. This argument is surprisingly anti-competitive. If it were true that rooftop solar in combination with storage could provide the same or better electric service at an equal or lower price, then it would not be in the public interest for utility commissions to structure rates that blindly discourage defection. If the technology ever develops to this point, and if customers can do without the utility and be equally well off or even better off, the underlying economics of the market should drive how rooftop solar is priced.

The truth, however, is that not only are we a very long way from facing that problem, given the ongoing advantages of economies of scale, but it is not even in the interest of solar customers to abandon the grid and thereby lose the opportunity of selling their excess generation (i.e. capturing the value of their own scale economies), as well as of having the grid as a full service backup. The danger I see is not that distributed energy resources will out-compete utility services under rational pricing; it is that if we follow the paths sought by Ms. Kobor and Mr. Beach, we would adopt a system so rife with cross-subsidies and uncompetitive pricing that some customers might be better off defecting than carrying the burden of cross-subsidies, leaving everyone—defectors and traditional customers alike—much worse off than they would have been under a well-priced utility system. Indeed, there is far more historical precedent for uneconomic bypass on electric utility systems than there is for going off-grid to realize real economic benefits.

This last scenario highlights what is at stake in this proceeding—any errors made in developing a value of solar methodology, if this aim is pursued, may well be multiplied by attempts to apply this methodology more broadly. It is thus vital to avoid crediting false values and adopting a form of value analysis that will not produce efficient or fair results for customers. In short, we know from the PURPA experience I laid out in my direct testimony "how this movie will end"--very unhappily, so why make the film at all, when we have rational, efficient, and fully compensatory pricing methods (cost and/or market) which will serve us much better?

Q. DOES THE TESTIMONY OF MS. KOBOR AND MR. BEACH COMPARE THE VALUE OF ROOFTOP SOLAR GENERATION TO ANY OTHER COMPETING RESOURCES?

A. The only competing resource Ms. Kobor and Mr. Beach benchmark their value analysis against is natural gas.[39] Their analyses are examples of the problem of not considering the potentially greater value offered by other resources, such as grid-scale solar, which I identified in my earlier testimony. Throughout their analyses, Ms. Kobor and Mr. Beach assume that the marginal resource displaced by rooftop solar is natural gas generation, and therefore that more rooftop solar necessarily means fewer emissions of carbon and other pollutants. While it may be a reasonable assumption that gas is the marginal resource being displaced short-term, that assumption provides us no actual data as to exactly what saving or benefits might be derived, or costs incurred, due to that fact. Taking that next step to actually quantify the costs and benefits of displacing natural gas fired generation requires a highly sophisticated, highly granular analysis which is both costly and ultimately highly contestable.[40]

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[39] That is, natural gas is the only resource they benchmark against in any quantitative sense. Mr. Beach does have a qualitative discussion of the value of rooftop solar vs. grid-scale solar, which I discuss briefly below.

[40] While displacing gas fired generation may have the immediate benefit of reducing carbon, the additional strains imposed by requiring gas plants to be ramped up and down will cause additional wear and tear on plants that can not only be costly, but is likely to cause the plants to be less efficient in their operations, increasing both costs and carbon emissions. Thus, identifying the exact amount of reduction of carbon emissions is a highly complex calculation, and that assumes that there is a net reduction over time, something we cannot be certain of. Whatever value, if any, is derived from the calculation will then have to be tested against the opportunity cost of being able to attain the same level of emissions reduction via less expensive means, such as trading RECs, energy efficiency, and/or grid-scale renewables. It is very revealing that neither Ms. Kobor nor Mr. Beach ever even raise the question of the

Q. HOW MIGHT ROOFTOP SOLAR ACTUALLY DISPLACE GRID-SCALE SOLAR INSTEAD OF NATURAL GAS?

A. It is not at all clear that in considering utility investment decisions, utilities with more rooftop solar will be less likely to invest in new natural gas plants when it comes to adding new generation. A more plausible scenario, it seems to me, is that a utility with an abundance of rooftop solar generation that it must integrate into its system will be most likely to cut back on investment into grid-scale solar power or other intermittent renewable power sources, reflecting its greater need for the flexibility, baseload, and ramping capability provided by natural gas plants. The ability to measure the "value" of avoided emissions from rooftop solar breaks down when we recognize that we don't know, over the medium to long term, what resource rooftop solar is displacing.

Q. HOW DO MS. KOBOR AND MR. BEACH RESPOND TO THE QUESTION OF WHAT THE VALUE OF SOLAR MEANS IN A WORLD OF MULTIPLE COMPETING RESOURCES?

A. Mr. Beach largely ignores this problem, except to the extent that he offers a few arguments for the superior value of rooftop solar over grid-scale solar. To the extent that Ms. Kobor acknowledges this problem, her response is to recommend that value analysis be applied to multiple resources (including "community and utility-scale solar, other renewables, and efficiency."[41] Writes Ms. Kobor, "[a]n important first step in any comparison would be to develop a robust methodology for fully valuing each resource.

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very real opportunity costs they would impose using their "value of solar" approach to pricing rooftop solar. (For more on the wear and tear costs of ramping, see, e.g., N. KUMAR ET AL., NREL, POWER PLANT CYCLING COSTS (2012), http://www.nrel.gov/docs/fy12osti/55433.pdf; Sonja Wogrin, *The Impact of Cycling Costs Due to Fatigue Damage on Optimal CCGT Operations*, Presentation to the Harvard Electricity Policy Group's 82nd Plenary Session (Mar. 11, 2016), http://www.ksg.harvard.edu/hepg/Papers/2016/March%202016/wogrin%20presentation.pdf; Debra Lew, *Coal/Gas Plant Cycling: Costs, Causes, Impacts*, Presentation to the Harvard Electricity Policy Group's 82nd Plenary Session (Mar. 11, 2016), http://www.ksg.harvard.edu/hepg/Papers/2016/March%202016/Lew%20Presentation.pdf.

[41] Kobor at 39:9-10.

Until such a methodology is used to analyze the value of specific resources, it is difficult to compare the value and cost of these different resources."[42] In effect, were we to follow her suggestion, we would abandon both market and cost based pricing for the highly speculative, imprecise, and arbitrary method of "value" pricing. To her credit, she does recognize that there are transaction costs, in the form of studies, associated with activities of that magnitude, especially if we applied it to all resources. What she ignores is the sheer magnitude of those costs, and the fact that no single study will be sufficiently definitive as to be uncontestable by all of the interests who participate in, or are affected by the outcome of, the proceedings of the ACC. Moreover, the consequences of value-based pricing to consumers would be too significant to ever consider moving forward with such an approach. Why should customers be forced to pay more for rooftop solar than they are currently paying for grid-scale solar as determined by the market?

Q. DOES MR. BEACH OFFER ANY COMPELLING REASON NOT TO COMPARE THE BENEFITS AND COSTS OF ROOFTOP SOLAR TO THOSE OF GRID-SCALE SOLAR?

A. No. Mr. Beach asserts a number of benefits of rooftop solar as opposed to grid-scale solar, none of which hold up to scrutiny (and which are certainly not quantifiable). "New capital," from the investments of rooftop solar customers, for example, is one he mentions—but there is no reason to prefer this source of capital to more traditional financing (this is not "free" capital – just as with more traditional forms of financing, a rate of return is expected). "Grid services," to the extent these exist, would come from the inverters, not the solar power itself, and are at this point potential, rather than reality. Other benefits include "new competition" and "high tech synergies," (fine things, potentially, except that the pricing generally proposed for rooftop solar has the effect of

[42] *Id.* at 39:10-13.

insulating rooftop solar from meaningful competition, even with other, more efficient, rooftop solar installations, eliminating incentives to adopt productivity-enhancing technologies like storage); and "enhanced reliability and resiliency"—a benefit which, if it exists at all, accrues only to the individual solar customer, since supply to the distribution network must be cut off, for safety reasons, in case of a distribution outage (I explain this in more detail in my original testimony, p. 39). Two final categories, "customer engagement" and "self-reliance" (with reference to Thomas Jefferson) are, in my opinion, far too subjective, and offer a benefit too specific to individual customers, to justify the payment of real money by customers without rooftop solar.[43] Why should we subsidize "self-reliance," rather than "cooperation," arguably an equally important element of American traditions?

III. SOME ITEMS TO CONSIDER, SHOULD THE COMMISSION WISH TO PURSUE VALUE OF SOLAR ANALYSIS, DESPITE ITS PROBLEMS

Q. DO YOU STILL MAINTAIN THAT A VALUE OF SOLAR ANALYSIS SHOULD NOT BE THE BASIS FOR HOW MUCH CUSTOMERS PAY FOR ROOFTOP SOLAR, AS OPPOSED TO MARKET AND/OR COST BASED PRICING?

A. Yes, I do. The whole notion of the "value of solar" neglects the crucial consideration of the opportunity costs of investing in solar rather than other resources. And the proposed analysis itself is so full of arbitrary estimates and judgments it is impossible to see how a "robust" value could emerge—still less, if we are supposed to do value analysis for multiple resources and compare the results.

[43] *See* Direct Testimony of R. Thomas Beach 30-32.

Q. IF THE COMMISSION NEVERTHELESS WANTS TO PURSUE THE IDEA OF VALUE OF SOLAR ANALYSIS, DO YOU HAVE ANY COMMENTS ON THIS?

A. If a value of solar analysis is going to be done, and taking the testimony of Ms. Kobor and Mr. Beach as examples, there are some clear problems that should be avoided.

Q. CAN YOU GIVE SOME EXAMPLES OF PROBLEMATIC ANALYTICAL CHOICES MADE OR SUGGESTED BY MR. BEACH AND MS. KOBOR?

A. Whenever it is suggested that customers should pay real money today for hypothetical and less than certain benefits tomorrow, one must proceed with great caution. One must take great care to consider all aspects of such an arrangement, including looking at all of the options to serve a defined need. This is particularly the case where it is not individuals making decisions affecting only themselves, but, rather, regulators making decisions that affect many tens of thousands of consumers. It is important to avoid unnecessary and asymmetrical shifts in risk allocation, incurring unnecessary costs, commitments to technology that may soon become obsolescent, or setting prices with no incentive for improving productivity. Neither Ms. Kobor nor Mr. Beach, in urging value based pricing for rooftop solar, even recognize the role that regulators must play in protecting consumers. They simply claim that rooftop solar has the values they claim, and no further consideration, or than offsetting the value asserted by the minimal costs they identify, is in order. A few issues that seem particularly worth highlighting in the analysis presented by Ms. Kobor and Mr. Beach are highlighted below:

- The insistence on long term analysis multiplies the number of potentially arbitrary or controversial analytical choices that must be made, starting with the choice of discount rate. The potential for arbitrary skewing of the analysis is multiplied further when analysts pick and choose some elements to be considered over the long term and some elements to be analyzed over the short term.

- The idea that rooftop solar offers utilities a value as a hedge against possible increases in natural gas prices is simply wrong, and should be dropped entirely.

- If a "value" analysis based on benefits and costs is to be undertaken, costs should be considered with at least as much thoroughness as benefits. In the case of Ms. Kobor and Mr. Beach, the list of costs considered, not surprisingly, is not nearly as comprehensive as the list of benefits considered. Indeed, that asymmetry is foundational to the approach they advocate: that benefits be maximized (indeed, often simply assumed) and costs minimized (indeed, often simply ignored).

Q. CAN YOU EXPLAIN FURTHER WHY YOU SEE THE LONG TERM LEVELIZED ANALYSIS OF BENEFITS ENDORSED BY MS. KOBOR AND MR. BEACH AS MULTIPLYING THE ANALYTICAL PROBLEMS AND ARBITRARINESS OF VALUE OF SOLAR ANALYSIS?

A. Ms. Kobor and Mr. Beach insist that an appreciation of the full value of rooftop solar requires that analysts look out twenty or thirty years into the future—a requirement that greatly multiplies the difficulty in conducting a robust, impartial, and even remotely accurate analysis of the value provided by rooftop solar. At the most fundamental level, it introduces the question of selecting a discount rate, something Ms. Kobor terms a "crucial assumption in a levelized cost analysis." Ms. Kobor rejects the discount rate typically used by utilities (6%-9%) in favor of a rate "similar to inflation," (in today's economy, presumably a very low rate). Mr. Beach uses two different rates in the updated analysis of the benefits and costs of solar in Arizona, using the utility's 7.2% discount rate in much of his analysis, but switching to a lower 3% "social discount rate" in calculating "societal" benefits, such as carbon emissions reductions.[44] The lower rate makes future benefits and costs look bigger; the higher rate makes them look smaller.

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[44] R. THOMAS BEACH AND PATRICK G. MCGUIRE, THE BENEFITS AND COSTS OF SOLAR DISTRIBUTED GENERATION FOR ARIZONA PUBLIC SERVICE 7, 17 (2016) (Attached to Mr. Beach's direct testimony in this docket).

My purpose here is not to judge what the appropriate discount rate is—it is simply to point out that this is a crucial analytical decision with significant implications for how big or small the "values" look that come out of value of solar analysis. And there is far from being a consensus as to what the correct rate is. A second crucial issue relates to mixing long term with short term analysis. Both Mr. Beach and Ms. Kobor insist that long-term analysis is crucial—except when it comes to analyzing the capacity value of rooftop solar. (Over the long term, the capacity value of rooftop solar is expected to decline significantly as rooftop solar penetration increases and as panels age). In this one case, Ms. Kobor argues for a "near term" look, because "[t]he valuation of DG exports will be most relevant if it examines current and/or near-term expected penetration levels on the utility's system." I don't know about "most relevant." Certainly, the valuation will be higher if it is focused on the near term. Similarly, Mr. Beach argues that future capacity value declines are too hard to predict—so in his Arizona analysis, he uses the capacity value of "solar installed today" for his entire "levelized" analysis.[45] I don't necessarily disagree with Ms. Kobor and Mr. Beach's caution in this case about trying to project costs decades into the future—I just wish they showed similar caution in all cases. The approach they choose (long term or near term) appears to have the self-serving characteristic of attributing the greatest value to rooftop solar.

Q. WHY DO YOU SUGGEST, ABOVE, THAT THE IDEA THAT ROOFTOP SOLAR OFFERS UTILITIES A VALUE AS A HEDGE AGAINST POSSIBLE INCREASES IN NATURAL GAS PRICES SHOULD BE DROPPED ENTIRELY?

A. Mr. Beach and Ms. Kobor both argue that there is a "hedging value" for rooftop solar that is realized by the utilities. The argument is based on the true observation that the marginal cost of solar electricity production is zero, whereas the marginal cost of the

[45] *Id.* at 13.

production of electricity from a natural gas plant goes up and down with the price of natural gas.

So solar power potentially does have a value as a hedge against natural gas, but only for the owner of the solar panels. For a utility that will be buying power from solar panel owners, the hedge value under net metering is nil. The reason is that the price to be paid by the utility for power from rooftop solar will include all of the elements included in the monthly electric utility bill, including the full cost of energy. When gas is expensive, this price paid by non-solar customers will be higher; when it is cheaper, it will be lower. There is no mechanism envisioned by anyone on either side of this debate (as far as I am aware) under which gas prices would be high, but solar producers would be compensated at a rate lower than the cost of electricity produced from gas generators. So, if it is worth hedging against variations in the price of natural gas, the utility should buy the same hedge against variations in the price of rooftop solar power. From the utility's and the non-solar customer's point of view, the two costs will vary together. Thus, the hedge value is not only zero, any consideration paid for such a hedge would be more expensive than incurring the risk from which protection is sought.

With that said, solar can provide a hedge for the owner of the solar panels. Thus, in the case of larger-scale, utility-owned solar plants, there could be a hedge value. But for rooftop solar panels, whatever hedge value may exist stays with the owners of the solar panels—it does not transfer to the utility. It should therefore be dropped from the list of "values" provided to the utility by rooftop solar.

Q. ARE THE COSTS IDENTIFIED BY MR. BEACH AND MS. KOBOR COMPREHENSIVE?

A. No, they are not. Ms. Kobor lists the costs of payments to customers and "integration costs and benefits." Beach lists lost revenue, integration, and administrative/interconnection costs.

Neither Mr. Beach nor Ms. Kobor bring anywhere near the same comprehensive, creative thoroughness to the identification of costs as they do to their much more extensive list of benefits. To correct the balance, let me suggest that the following costs should also be considered:

- The wear and tear on natural gas and other thermal plants caused by additional cycling to accommodate solar power's production profile;
- The cost of additional regulation services needed to supply necessary reactive power not supplied by rooftop solar generation;
- The cost of providing additional power regulation, as some of the physical inertia provided to the system by large turbines is lost;
- Incremental changes to distribution system caused by the presence of and unplanned additions of rooftop solar to the system;
- Lost revenues caused by net metering enabled avoidance of paying fixed and demand charges;
- The economic and job losses caused by higher electricity rates, caused by paying above market prices to rooftop solar vendors/lessors and/or displacement of jobs in other sectors of the electricity market, such as thermal plants;
- The costs of additional reporting and analysis necessary to support extensive new 'valuation" efforts;

- The costs to society of a policy that, in the aggregate, transfers money from poorer households to richer households;
- The opportunity costs of investing money in a less efficient resource, as opposed to more cost-effective forms of clean energy;
- The costs of inefficiency in the production of rooftop solar power perpetuated by uncompetitive compensation of this power;
- The taxes and cross-subsidies that are used to subsidize rooftop solar;
- The cost associated with protecting rooftop solar vendors/lessors from market pressure to pass on declining panel costs;
- While not a cost, *per se*, the risk that rooftop solar may, as in the final EPA Rules under the Clean Power Plan, not be considered as a basic building block for a state plan of compliance, or may prove to be a highly inefficient method of carbon reduction;
- The costs associated with displacing lower cost energy with higher price rooftop solar;
- The costs associated with a pricing regime that fails to recognize that rooftop solar is largely off peak;
- The costs associated with having to incur sufficient capacity to back up intermittency in rooftop solar energy supply;
- The costs associated with the reallocation of capital from more efficient sources of generation (e.g., grid-scale renewables) to less efficient but higher priced rooftop solar; and

- Finally, the costs associated with all of the studies and litigation associated with value of solar pricing (recognized by Ms. Kobor but not by Mr. Beach). This is particularly burdensome for commissions and their staff.

Q. IS THERE ANY OVERALL PATTERN IN THE PROBLEMS WITH MS. KOBOR AND MR. BEACH'S VALUE OF SOLAR ANALYSIS?

A. Yes. Whenever there is uncertainty/risk, Ms. Kobor and Mr. Beach use their value analysis to put the risk on ratepayers. There is one telling moment in Mr. Beach's testimony that suggests he is well aware that there is something wrong with the value analysis he is offering. In arguing for the benefits of a minimum bill, Mr. Beach writes, "A minimum bill can address impacts on non-participants by providing DG vendors with a signal to reduce the sizing of DG system to keep customers above the minimum bill level, thus reducing the costs of net metering for other ratepayers."[46] Mr. Beach's cost benefit analysis in fact shows a (small) benefit to other ratepayers from net metering. If this benefit were real, presumably, the more of it ratepayers could get, the better. Instead, Mr. Beach's true opinion seems to be that less of this particular benefit is what is best for ratepayers—presumably because he recognizes the obvious, which is that exchanging real money today for hypothetical, uncertain "benefits" tomorrow is not a good bargain for anybody.

IV. <u>CONCLUSION</u>

Q. ANY CONCLUDING THOUGHTS?

A. First, there is a lot at stake here, especially if, as suggested by Ms. Kobor and Mr. Beach, this is to become a template for valuing all kinds of distributed energy services.

[46] R. Thomas Beach Direct Testimony 28.

Any errors or overestimates of benefits that get baked into a "value of solar" analysis may end up multiplying, not only as rooftop solar itself grows, but as other distributed energy resources begin to develop and clamor for the same benefits.

Second, it is pretty clear that when you do these value of solar studies, you can direct them to any conclusion you want to make. These studies are packed with "data" selected by the author of the study and can be used to prove whatever you want it to prove, as the range of findings on value of solar studies makes clear.

Third, it is worth remembering that there are alternatives to the uncertainties of value of solar analysis. We should use market-based or market-derived (e.g., benchmarks from the wholesale market, real time energy prices) pricing wherever possible. Another option, of course, is cost based pricing.

Finally, it is important not to view rooftop solar in the out of context fashion that both Mr. Beach and Ms. Kobor do. Rooftop solar is but one option among a number of others for meeting our energy needs. For it to prosper and be in the mainstream of Arizona's energy mix, it must be cost effective and competitive. Isolating it into an isolated, non-mainstream, corner of the energy market by using "value pricing," as opposed to market or cost based pricing is a big mistake that threatens the long-term viability of rooftop solar and deprives consumers of a cost effective resource.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

APS EXHIBIT ______

EXHIBIT

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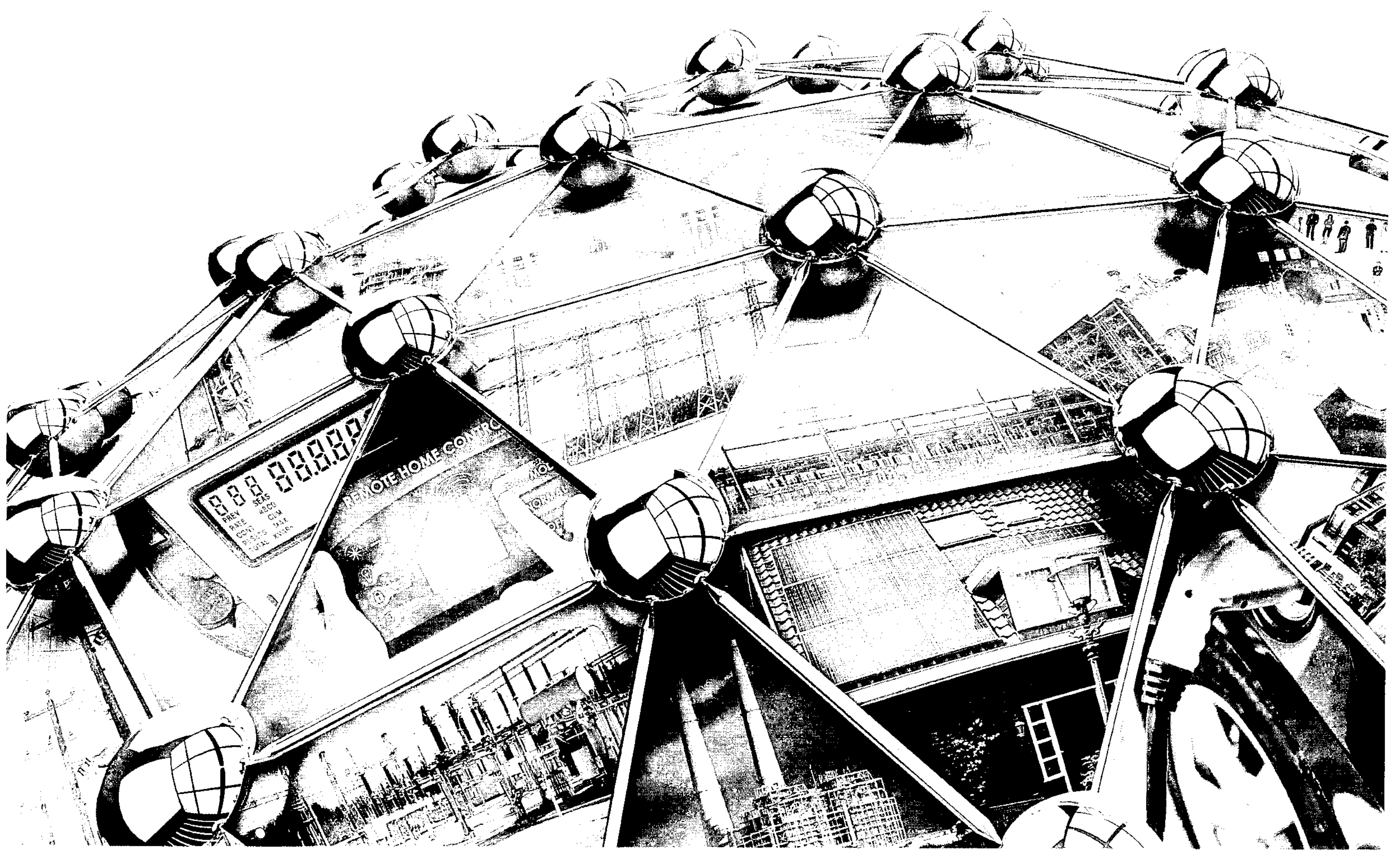
THE INTEGRATED GRID

REALIZING THE FULL VALUE OF CENTRAL AND DISTRIBUTED ENERGY RESOURCES



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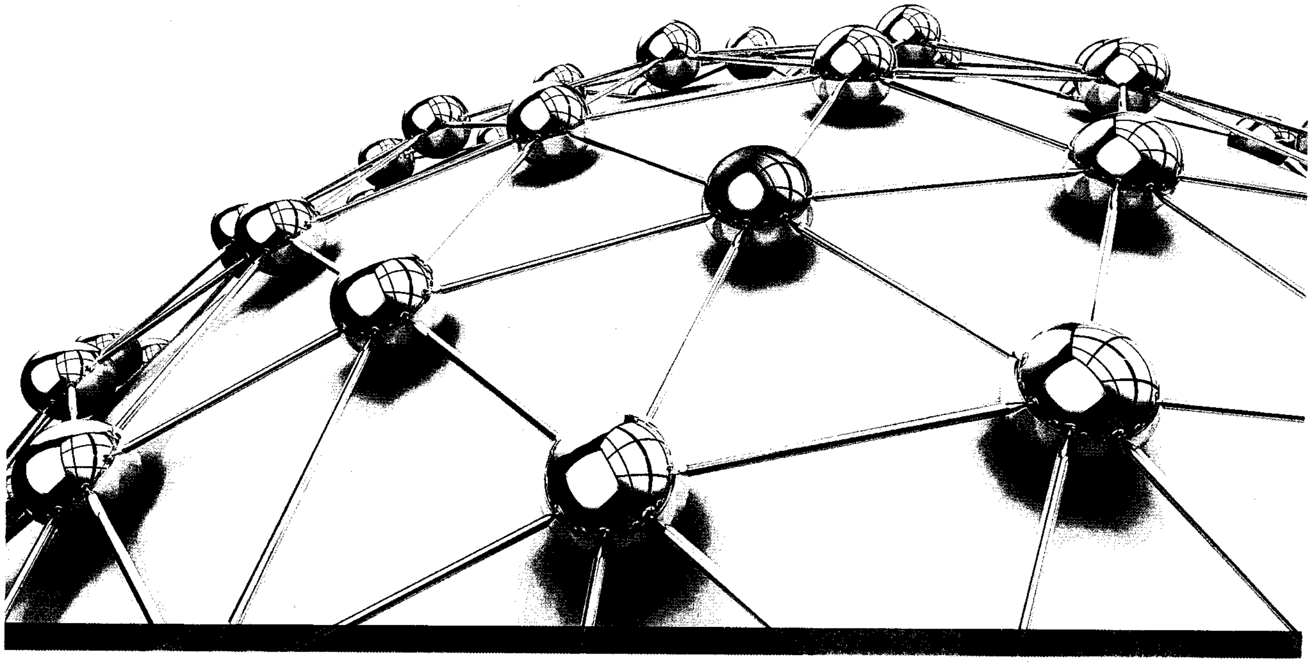

Executive Summary

The electric power system has evolved through large, central power plants interconnected via grids of transmission lines and distribution networks that feed power to customers. The system is beginning to change—rapidly in some areas—with the rise of distributed energy resources (DER) such as small natural gas–fueled generators, combined heat and power plants, electricity storage, and solar photovoltaics (PV) on rooftops and in larger arrays connected to the distribution system. In many settings DER already have an impact on the operation of the electric power grid. Through a combination of technological improvements, policy incentives, and consumer choices in technology and service, the role of DER is likely to become more important in the future.

The successful integration of DER depends on the existing electric power grid. That grid, especially its distribution systems, was not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. The technical characteristics of certain types of DER, such as variability and intermittency, are quite different from central power stations. To realize fully the value of distributed resources and to serve all consumers at established standards of quality and reliability, the need has arisen to integrate DER in the planning and operation of the electricity grid and to expand its scope to include DER operation—what EPRI is calling *the Integrated Grid.*

The grid is expected to change in different, perhaps fundamental ways, requiring careful assessment of the costs and opportunities of different technological and policy pathways. It also requires attention to the reality that the value of the grid may accrue to new stakeholders, including DER suppliers and customers.

This paper is the first phase in a larger Electric Power Research Institute (EPRI) project aimed at charting the transformation to the Integrated Grid. Also under consideration will be new business practices based on technologies, systems, and the potential for customers to become more active participants in the power system. Such information can support prudent, cost-effective investment in grid modernization and the integration of DER to enable energy efficiency, more responsive demand, and the management of variable generation such as wind and solar.[1]

Along with reinforcing and modernizing the grid, it will be essential to update interconnection rules and wholesale market and retail rate structures so that they adequately value both capacity and energy. Secure communications systems will be needed to connect DER and system operators. As distributed resources penetrate the power system more fully, a failure to plan for these needs could lead to higher costs and lower reliability.

Analysis of the Integrated Grid, as outlined here, should not favor any particular energy technology, power system configuration, or power market structure. Instead, it should make it possible for stakeholders to identify optimal architectures and the most promising configurations —recognizing that the best solutions vary with local circumstances, goals, and interconnections.

Because local circumstances differ, this paper illustrates how the issues that are central to the Integrated Grid are playing out in different power systems. For example, Germany's experience illustrates consequences for price, power quality, and reliability when the drive to achieve a high penetration of distributed wind and PV results in outcomes that were not fully anticipated. As a result, German policymakers and utilities now are changing interconnection rules, grid expansion plans, DER connectivity requirements, wind and PV incentives, and operations to integrate distributed resources.

In the United States, Hawaii has experienced a rapid deployment of distributed PV technology that is challenging the power system's reliability. In these and other jurisdictions, policymakers are considering how best to recover the costs of an integrated grid from all consumers that benefit from its value.

[1] *This paper is about DER, but the analysis is mindful of the ways that DER and grid integration could affect energy efficiency and demand response as those could have large effects as well on the affordability, reliability, and environmental cleanliness of the grid.*

Action Plan

The current and projected expansion of DER may significantly change the technical, operational, environmental, and financial character of the electricity sector. An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. Interconnection Rules and Communications Technologies and Standards
   - ***Interconnection rules*** that preserve voltage support and grid management
   - ***Situational awareness*** in operations and long-term planning, including rules of the road for installing and operating distributed generation and storage devices
   - Robust ***information and communication technologies***, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cyber security
   - A ***standard language and a common information model*** to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems
2. Assessment and Deployment of Advanced Distribution and Reliability Technologies
   - ***Smart inverters*** that enable DER to provide voltage and frequency support and to communicate with energy management systems [1]
   - ***Distribution management systems and ubiquitous sensors*** through which operators can reliably integrate distributed generation, storage, and end-use devices while also interconnecting those systems with transmission resources in real time [2]
   - ***Distributed energy storage and demand response***, integrated with the energy management system [3]
3. Strategies for Integrating DER with Grid Planning and Operation
   - ***Distribution planning and operational processes*** that incorporate DER
   - ***Frameworks for data exchange and coordination*** among DER owners, distribution system operators (DSOs), and organizations responsible for transmission planning and operations
   - Flexibility to ***redefine roles and responsibilities*** of DSOs and independent system operators (ISOs)
4. Enabling Policy and Regulation
   - ***Capacity-related costs*** must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
   - ***Power market rules*** that ensure long-term adequacy of both energy and capacity
   - ***Policy and regulatory framework*** to ensure that costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
   - ***New market frameworks*** using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs

Next Steps for EPRI and Industry

EPRI has begun work on a three-phase initiative to provide stakeholders with information and tools that will be integral to the four areas of collaboration outlined above:

Phase I – A concept paper (this document) to align stakeholders on the main issues while outlining real examples to support open fact-based discussion. Input and review were provided by various stakeholders from the energy sector including utilities, regulatory agencies, equipment suppliers, non-governmental organizations (NGOs), and other interested parties.

Phase II – This six-month project will develop a framework for assessing the costs and benefits of the combinations of technology that lead to a more integrated grid. This includes recommended guidelines, analytical tools, and procedures for demonstrating technologies and assessing their unique costs and benefits. Such a framework is required to ensure consistency in the comparison of options and to build a comprehensive set of data and information that will inform the Phase III demonstration program. Phase II output will also support policy and regulatory discussions that may enable integrated grid solutions.

Phase III – Conduct global demonstrations and modeling using the analytics and procedures developed in Phase II to provide comprehensive data and information that stakeholders will need for the system-wide implementation of integrated grid technologies in the most cost-effective manner.

Taken together, Phases II and III will help identify the technology combinations that will lead to cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. Additionally, interface requirements that help define the technical basis for the relationship between DER owners, DSOs, and transmission system operators (TSOs) or ISOs will be developed. Finally, the information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system while supporting the robust evaluation of the capacity and energy contribution from both central and distributed resources.

The development of a consistent framework supported by data from a global technology demonstration and modeling program will support cost-effective, prudent investments to modernize the grid and the effective, large-scale integration of DER into the power system. The development of a large collaborative of stakeholders will help the industry move in a consistent direction to achieve an integrated grid.

Key Points – The Integrated Grid

Several requirements are recognized when defining an integrated grid. It must enhance electrical infrastructure, must be universally applicable, and should remain robust under a range of foreseeable conditions:

- Consumers and investors of all sizes are installing DER with technical and economic attributes that differ radically from the central energy resources that have traditionally dominated the power system.
- So far, rapidly expanding deployments of DER are *connected* to the grid but not *integrated* into grid operations, which is a pattern that is unlikely to be sustainable.
- Electricity consumers and producers, even those that rely heavily on DER, derive significant value from their grid connection. Indeed, in nearly all settings the full value of DER requires grid connection to provide reliability, virtual storage, and access to upstream markets.
- DER and the grid are not competitors but complements, provided that grid technologies and practices develop with the expansion of DER.
- We estimate that the cost of providing grid services for customers with distributed energy systems is about $51/month on average in the typical current configuration of the grid in the United States; in residential PV systems, for example, providing that same service completely independent of the grid would be four to eight times more expensive.
- Increased adoption of distributed resources requires interconnection rules, communications technologies and standards, advanced distribution and reliability technologies, integration with grid planning, and enabling policy and regulation.
- Experience in Germany provides a useful case study regarding the potential consequences of adding extensive amounts of DER without appropriate collaboration, planning, and strategic development.
- While this report focuses on DER, a coherent strategy for building an integrated grid could address other challenges such as managing the intermittent and variable supply of power from utility-scale wind and solar generators.

Today's Power System

Today's power system was designed to connect a relatively small number of large generation plants with a large number of consumers. The U.S. power system, for example, is anchored by ~1,000 gigawatts (GW) of central generation on one end, and on the other end are consumers that generally do not produce or store energy [4] [5]. Interconnecting those is a backbone of high-voltage transmission and a medium- and low-voltage distribution system that reaches each consumer. Electricity flows in one direction, from power plants to substations to consumers, as shown in Figure 1. Even with increasing penetration, U.S. distributed resources account for a small percent of power production and consumption and have not yet fundamentally affected that one-way flow of power.

Energy, measured in kilowatt-hours (kWh), is delivered to consumers to meet the electricity consumption of their lighting, equipment, appliances, and other devices, often called *load*. *Capacity* is the maximum capability to supply and deliver a given level of energy at any point in time. *Supply capacity* comprises networks of generators designed to serve load as it varies from minimum to maximum values over minutes,

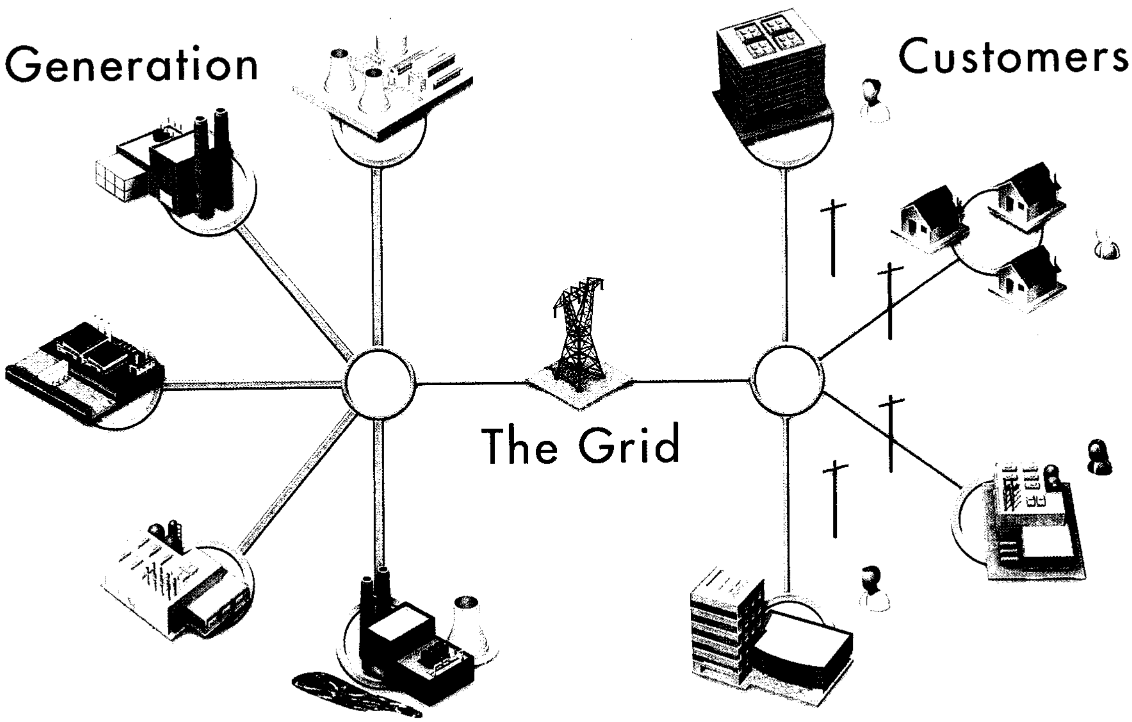

Figure 1: Today's Power System Characterized by Central Generation of Electricity, Transmission, and Distribution to End-Use Consumers.

hours, days, seasons, etc. *Delivery capacity* is determined by the design and operation of the power transmission and distribution systems that deliver the electricity to consumers. The system's supply and delivery capacity plan is designed to serve the expected instantaneous maximum demand over a long-term planning horizon.

Because the whole grid operates as a single system in real time and the lead times for building new resources are long, planning is essential to ensuring the grid's adequacy. Resource adequacy planning determines the installed capacity required to meet expected load with a prescribed reserve margin that considers potential planned and unplanned unavailability of given generators. In addition to providing sufficient megawatts to meet peak demand, the available generation (along with other system resources) must provide specific operating capabilities to ensure that the system operates securely at all times. These ancillary services include frequency regulation, voltage support, and load following/ramping. As a practical matter, the reliability of grid systems is highly sensitive to conditions of peak demand when all of these systems must operate in tandem and when reserve margins are smallest.

Today's power system has served society well, with average annual system reliability of 99.97% in the United States, in terms of electricity availability [6]. The National Academy of Engineering designated electrification enabled by the grid as the top engineering achievement of the twentieth century. Reliable electrification has been the backbone of innovation and growth of modern economies. It has a central role in many technologies considered pivotal for the future, such as the internet and advanced communications.

Today's power system has served society well, with average annual system reliability of 99.97% in the U.S., in terms of electricity availability.

The Growth in Deployment of Distributed Energy Resources

The classic vision of electric power grids with one-way flow may now be changing. Consumers, energy suppliers, and developers increasingly are adopting DER to supplement or supplant grid-provided electricity. This is particularly notable with respect to distributed PV power generation—for example, solar panels on homes and stores—which has increased from approximately 4 GW of global installed capacity in 2003 to nearly 128 GW in 2013 [7]. In Germany, the present capacity of solar generation is approximately 36 GW, while the daily system peak demand ranges from about 40 to 80 GW. By the end of 2012, Germany's PV capacity was spread across approximately 1.3 million residences, businesses, and industries and exceeded the capacity of any other single power generation technology in the country [8]. This rapid spread of DER reflects a variety of public and political pressures along with important changes in technology. This paper focuses on system operation impacts as DER reaches large scales.

By the end of 2013, U.S. PV installations had grown to nearly 10 GW. Although parts of the U.S. have higher regional penetration of PV, this 10 GW represents less than 2% of total installed U.S. generation capacity [9], which matches German PV penetration in 2003 (Figure 2). With PV growth projected to increase in scale and pace over the next decade, now is the time to consider lessons from Germany and other areas with high penetration of distributed resources.

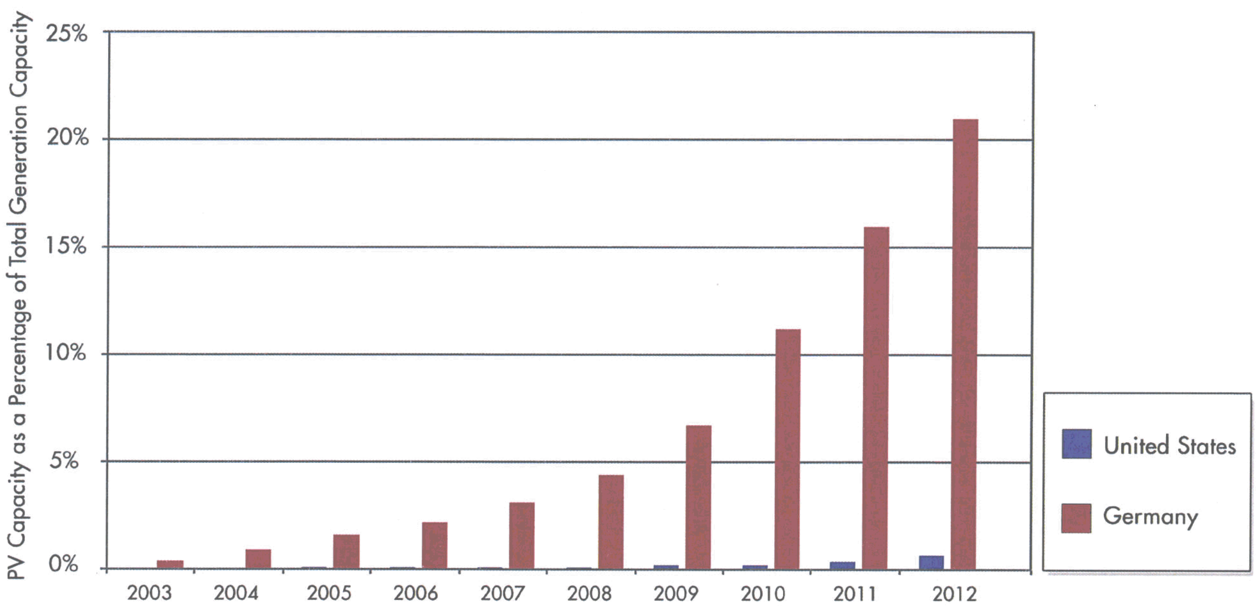

Figure 2: U.S. PV Capacity as a Percentage of Total Capacity Compared with Germany at the Beginning of Its "Energy Transformation."

In addition to Germany, high penetration of distributed PV is evident in California, Arizona, and Hawaii and in countries such as Italy, Spain, Japan, and Australia [7]. Beyond PV, other distributed resources are expanding and include such diverse technologies as batteries for energy storage, gas-fired micro-generators, and combined heat and power (CHP) installations—often referred to as *cogeneration*. In the United States natural gas prices and the cost and efficiency of gas-fired technologies have made these options effectively competitive with retail electricity service in some regions, for some consumers [10]. In jurisdictions where power prices are high, even more costly DER such as solar PV can be competitive with grid-supplied power.

In most cases, grid-connected DER benefit from the electrical support, flexibility, and reliability that the grid provides, but they are not integrated with the grid's operation. Consequently, the full value of DER is not realized with respect to providing support for grid reliability, voltage, frequency, and reactive power.

Distributed PV power generation has increased from approximately 4 GW of global installed capacity in 2003 to nearly 128 GW in 2013.

Germany's Experience: More Distributed but Not Integrated

The circumstances surrounding Germany's extensive deployment of distributed solar PV and wind offers important lessons about the value of planning for integration of DER, both economic and technical. Germany's experience is unique for these reasons:

- Germany represents a large interconnected grid with extensive ties with other grids, which is similar to the U.S. and other countries.
- The penetration of DER over the past decade is substantial (~68 GW of installed capacity of distributed PV and wind generation over 80 GW of peak load).
- The observed results, in terms of reliability, quality, and affordability of electricity, are not based on a hypothetical case or on modeling and simulations.
- This growth in penetration of DER occurred without considering the integration of these resources with the existing power system.
- Germany has learned from this experience, and the plan for continuing to increase the deployment of solar PV and wind generation hinges on many of the same integrated grid ideas as outlined in this paper.

German deployment was driven by policies for renewable generation that have commanded widespread political support. PV and wind generation are backed by the German Renewable Energy Sources Act (EEG), which stipulates feed-in tariffs[2] (FIT) for solar power installations. This incentive, which began in 2000 at €0.50/kWh ($0.70/kWh) for a period of 20 years, has stimulated major deployment of distributed renewable generation.

In the meantime, electricity rates have increased in Germany, for various reasons, to an average residential rate in 2012 of €0.30/kWh ($0.40/kWh), more than doubling residential rates since 2000 [8]. These higher electricity rates and lower costs for DER, due to technology advancements and production volume, have turned the tables in Germany. Today, the large FIT incentives are no longer needed, or offered, to promote new renewable installations.[3]

Notably, the desire to simultaneously contain rising electricity rates while promoting deployment of renewable energy resources has led to an evolution in German incentive policy for distributed renewable generation. For residential PV the FIT has dropped from ~ €0.50/kWh in 2000 to ~ €0.18/kWh today. An electricity price greater than the FIT has resulted in a trend of self-consumption of local generation. To ensure that all customers are paying for the subsidy for PV, the German cabinet in January 2014 approved a new charge on self-consumed solar power. Those using their own solar-generated electricity will be required to pay a €0.044kWh ($0.060/kWh) charge. Spain is considering similar rate structures to ensure that all customers equitably share the cost. Still to be resolved is how grid operating and infrastructure costs will be recovered from all customers who utilize the grid with increasing customer self-generation.

Technical repercussions have resulted from DER's much larger share of the power system. Loss of flexibility in the

[2] *Feed-in tariffs are a long-term guaranteed incentive to resource owners based on energy production (in kWh), which is separately metered from the customer's load.*

[3] *PV installations commissioned in July 2013 receive €0.104 to €0.151/kWh ($0.144 to $0.208/kWh) for a period of 20 years.*

generation fleet prompted the operation of coal plants on a "reliability-must-run" basis. Distributed PV was deployed with little time to plan for effective integration. Until the last few years and the advent of grid codes, PV generators were not required to respond to grid operating requirements or to be equipped to provide grid support functions, such as reactive power management or frequency control. Resources were located without attention to the grid's design and power flow limitations. The lack of coordination in planning and deploying DER increases the cost of infrastructure upgrades for all customers and does not provide the full value of DER to power system operation. Rapid deployments have led to several technical challenges:

1. Local over-voltage or loading issues on distribution feeders. Most PV installations in Germany (~80%) are connected to low-voltage circuits, where it is not uncommon for the PV capacity to exceed the peak load by three to four times on feeders not designed to accommodate PV. This can create voltage control problems and potential overloading of circuit components [11].

2. Risk of mass disconnection of anticipated PV generation in the event of a frequency variation stemming from improper interconnection rules.[4] This could result in system instability and load-shedding events [12]. The same risk also exists from both a physical or cyber security attack.

3. Resource variability and uncertainty have disrupted normal system planning, causing a notable increase in generation re-dispatch[5,6] events in 2011 and 2012 [13].

4. Lack of the stabilizing inertia from large rotating machines that are typical of central power stations[7] has raised general concern for maintaining the regulated frequency and voltage expected from consumers, as inverter-based generation does not provide the same inertial qualities [14].

[4] *Distributed PV in Germany initially was installed with inverters that are designed to disconnect the generation from the circuit in the event of frequency variations that exceed 50.2 Hz in their 50 Hz system. Retrofits necessary to mitigate this issue are ongoing and are estimated to cost approximately $300 million [12].*

[5] *German transmission system operator Tennett experienced a significant increase in generation re-dispatch events in 2011 and 2012 relative to previous years. Generation scheduling changes are required to alleviate power flow conditions on the grid or resource issues that arise on short notice rather than in the schedule for the day.*

[6] *While the primary driver to re-dispatch issues has been a reduced utilization of large nuclear generators, the increase in wind generation and PV in Germany is expected to continue changing power flow patterns.*

[7] *Many DER connect to the grid using inverters, rather than the traditional synchronous generators. Increasing the relative amount of distributed and bulk system inverter-based generation that displaces conventional generation will negatively impact system frequency performance, voltage control and dynamic behavior if the new resources do not provide compensation of the system voltage and frequency support.*

Smart inverters capable of responding to local conditions or requests from the system operator can help avoid distribution voltage issues and mass disconnection risk of DER. This type of inverter was not required by previous standards in Germany, although interconnection rules are changing to require deployment of smart inverters. (See the highlight box below for further information.)

The rate impacts and technical repercussions observed in Germany provide a useful case study of the high risks and unintended consequences resulting from driving too quickly to greater DER expansion without the required collaboration, planning, and strategies set forth in the Action Plan. The actions in Phases II and III should be undertaken as soon as it is feasible to ensure that systems in the United States and internationally are not subjected to similar unintended consequences that may negatively impact affordability, environmental sustainability, power quality, reliability, and resiliency in the electric power sector.

Smart Inverters and Controls

With the current design emphasis on distribution feeders supporting one-way power flow, the introduction of two-way power flow from distributed resources could adversely impact the distribution system. One concern is over-voltage, due to electrical characteristics of the grid near a distributed generator. This could limit generation on a distribution circuit, often referred to as *hosting capacity*. Advanced inverters, capable of responding to voltage issues as they arise, can increase hosting capacity with significantly reduced infrastructure costs [15], [16].

German Grid Codes

In Germany, grid support requirements are being updated so that distributed resources can be more effectively integrated with grid operation [17], [18]. These requirements, called *grid codes*, are developed in tandem with European interconnection requirements recommended by the European Network of Transmission System Operators (ENTSO-E) [19], [20]:

1. Frequency control is required of all generators, regardless of size. Instead of disconnecting when the frequency reaches 50.2 Hz, generator controls will be required to gradually reduce the generators' active power output in proportion to the frequency increase (Figure 3). Other important functions, such as low-voltage ride-through, are also required at medium voltage.

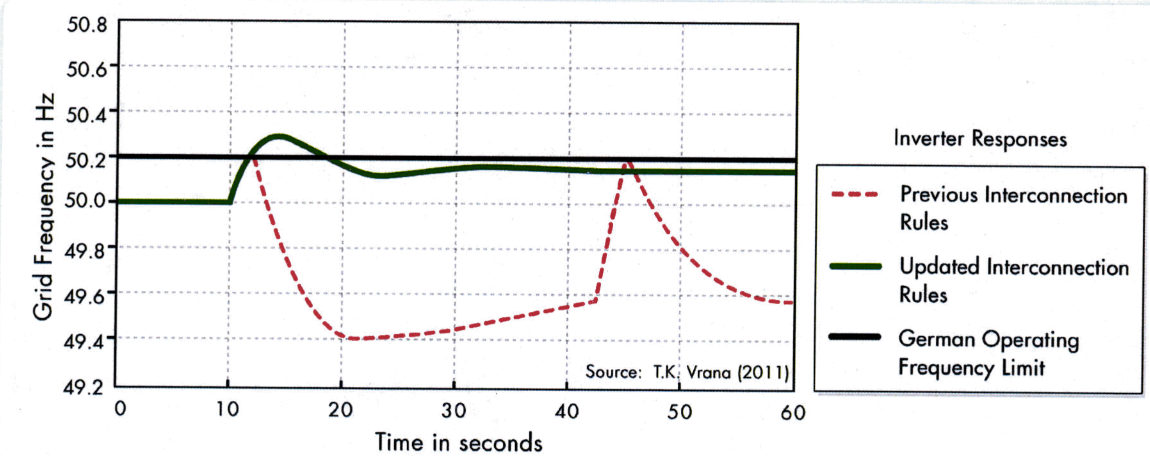

Figure 3: Example of Improved Performance with Inverter Controls That Implement a Droop Function for Over-Frequency Conditions Rather Than Tripping.

2. Voltage control functions are required from inverters, depending on the requirements of the DSO. Control methods include fixed power-factor operation, variable power factor as a function of active power, or reactive power management to provide voltage control.
3. Communication and energy management functions are now required of distributed resources, receiving commands from the system operator for active and reactive power management. As of 2012, this capability is required for all installations greater than 30 kVA. Systems less than 30 kVA without this capability are limited to 70% of rated output.

Germany is requiring that all existing inverters with a capacity greater than 3.68 kVA be retrofitted to include the droop function rather than instantly tripping with over-frequency. The cost of the retrofit associated with this function is estimated to be $300 million.

While necessary, these steps are probably still not enough to allow full integration of DER into the grid. Significant investment in the grid itself will be needed, including development of demand response resources (for example, electric transportation charging stations with time of use tariffs), and various energy storage systems. Also needed are markets and tariffs that value capacity and replacement of fossil-fueled heating plants with electric heating to take advantage of excess PV and wind capacity. German energy agency DENA determined that German distribution grids will require investment of €27.5 billion to €42.5 billion ($38.0 billion to $58.7 billion) by 2030. This includes expanding distribution circuits between 135,000 km and 193,000 km [21]. Extensive research is under way to develop and evaluate technologies to improve grid flexibility and efficiency with even more renewable capacity.

Assessing the Cost and Value of Grid Services

An electric grid connection, in ways different from a telephone line, provides unique and valuable services. Thirty percent of landline telephone consumers have canceled this service, relying solely on cellular service [22]. In contrast, virtually all consumers that install distributed generation remain connected to the grid. The difference is that the cellular telephone network provides functionality approximately equal to landline service, while a consumer with distributed generation will still need the grid to retain the same level of service. Unlike a cell phone user, operating without interconnection to this grid will require significant investment for on-site control, storage, and redundant generation capabilities.

This section characterizes the value of grid service to consumers with DER, along with calculations illustrating costs and benefits of grid connection. Subsequent sections focus on the value that DER can provide to the grid. In the context of value, it is important to distinguish the difference between value and cost. Value reflects the investments that provide services to consumers. It guides planning and investment decisions so that benefits equal or exceed costs. The costs that result are recovered through rates that, in a regulated environment, are set to recover costs, not to capture the full value delivered.

Value of Grid Service: Five Primary Benefits

Often, the full value of a grid connection is not fully understood. Grid-provided energy (kWh) offers clearly recognized value, but grid connectivity serves roles that are important beyond providing energy. Absent redundancy provided by the grid connection, the reliability and capability of the consumer's power system is diminished. Grid capacity provides needed power for overload capacity, may absorb energy during over-generation, and supports stable voltage and frequency. The primary benefits of grid connectivity to consumers with distributed generation are shown in Figure 4 and are described below.

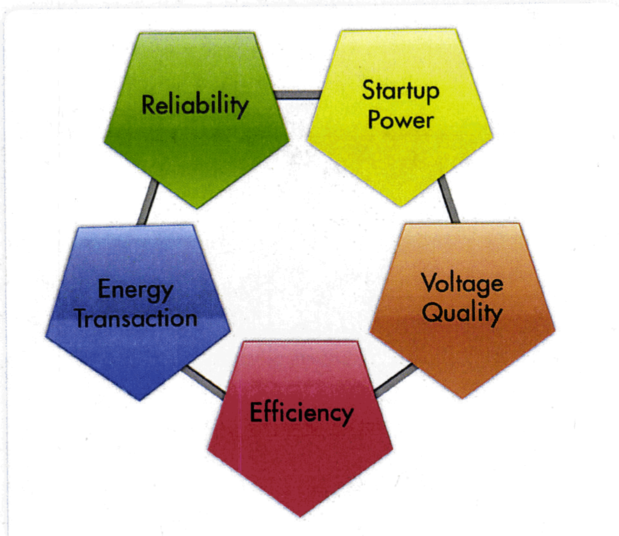

Figure 4: Primary Benefits of Grid Connectivity to Consumers with Distributed Generation.

1. **Reliability** – The grid serves as a reliable source of high-quality power in the event of disruptions to DER. This includes compensating for the variable output of PV and wind generation. In the case of PV, the variability is not only diurnal, but as shown in Figure 5, overcast conditions or fast-moving clouds can cause fluctuation of PV-produced electricity. The grid serves as a crucial balancing resource available for whatever period—from seconds to hours to days and seasons—to offset variable and uncertain output from distributed resources. Through instantaneously balancing supply and demand, the grid provides electricity at a consistent frequency. This balancing extends beyond real power, as the grid also ensures that the amount of reactive power in the system balances load requirements and ensures proper system operation.[8]

The need for reliability is fundamental to all DER, not just variable and intermittent renewable sources. For example, a customer depending solely on a gas-fired generator, which has an estimated reliability of 97%, is projected to experience 260 hours of power outage [23] compared with the 140 minutes of power outage that U.S. grid consumers experience on average (excluding major events such as hurricanes) [6]. Improvements in reliability are generally achieved through redundancy. With the grid, redundant capacity can be pooled among multiple consumers, rather than each customer having to provide its own backup resources. This reduces the overall cost of reliability for each customer [23].

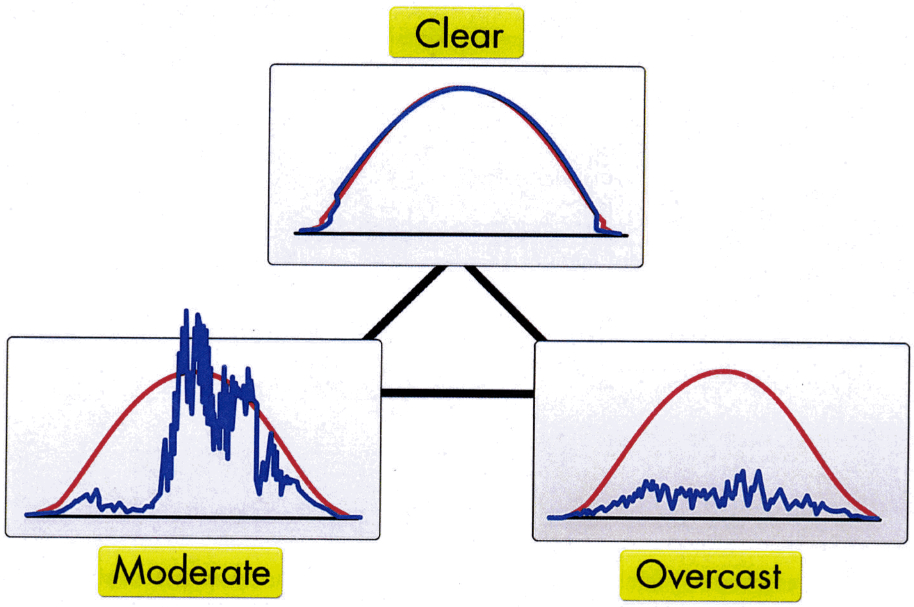

Figure 5: The Output of PV Is Highly Variable and Dependent on Local Weather.

[8] *Consumer loads typically require two different kinds of power, both real and reactive. Real power is a function of the load's energy consumption and is used to accomplish various tasks. Reactive power is transferred to the load during part of the cycle and returned during the other part, doing no work. Balancing both real and reactive power flow is a necessary function of a reliable electric grid.*

2. **Startup Power** – The grid provides instantaneous power for appliances and devices such as compressors, air conditioners, transformers, and welders that require a strong flow of current ("in-rush" current) when starting up. This enables them to start reliably without severe voltage fluctuation. Without grid connectivity or other supporting technologies,[9] a conventional central air conditioning compressor relying only on a PV system may not start at all unless the PV system is oversized to handle the in-rush current. A system's ability to provide this current is directly proportional to the fault contribution level.[10] Even if a reciprocating engine distributed generator is used as support, its fault level is generally five times less than the grid's [23]. The sustained fault current from inverter-based distributed resources is limited to the inverter's maximum current and is an order of magnitude lower than the fault level of the grid.

Figure 6 illustrates the instantaneous power required to start a residential air conditioner. The peak current measured during this interval is six to eight times the standard operating current [24]. While the customer's PV array could satisfy the real power requirements of the heating, ventilating, and air conditioning (HVAC) unit during normal operation, the customer's grid connection supplies the majority of the required starting power.

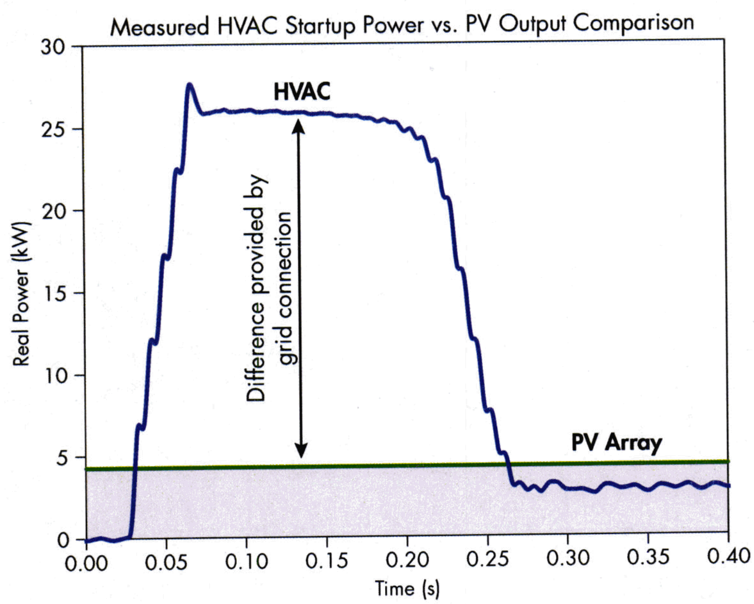

Figure 6: The Grid Provides In-Rush Current Support for Starting Large Motors, Which May Be Difficult to Replicate with a Distributed Generator.

[9] *Supporting technologies include variable-frequency drive (VFD) systems, which are able to start motors without the in-rush current common in "across-the-line" starting [24].*

[10] *Fault level is a measure of the current that would flow at a location in the event of short circuit. Typically used as a measure of electrical strength, locations with a high fault level are typically characterized by improved voltage regulation, in-rush current support, and reduced harmonic impact. Locations with a low fault level are more susceptible to voltage distortion and transients induced by harmonic-producing loads.*

3. **Voltage Quality** – The grid's high fault current level also results in higher quality voltage by limiting harmonic distortion[11] and regulating frequency in a very tight band, which is required for the operation of sensitive equipment. Similarly, the inherent inertia of a large connected system minimizes the impact of disturbances, such as the loss of a large generator or transmission line, on the system frequency. As shown in Figure 7, grid-connected consumers on average will experience voltage that closely approximates a sinusoidal waveform with very little harmonic distortion.

   In contrast, voltage from a distributed system that is not connected to the grid will generally have a higher voltage harmonic distortion, which can result in malfunction of sensitive consumer end-use devices. Harmonics cause heating in many components, affecting dielectric strength and reducing the life of equipment, such as appliances,[12] motors, or air conditioners [25]. Harmonics also contribute to losses that reduce system efficiency. In addition, a disturbance occurring inside the unconnected system will create larger deviations in frequency than if the system maintained its connection to the larger grid.

4. **Efficiency** – Grid connectivity enables rotating-engine-based generators to operate at optimum efficiency. Rotating-engine-based distributed resources, such as micro-turbines or CHP systems are most efficient when operating steadily near full output [26]. This type of efficiency curve is common for any rotating machine, just as automobiles achieve the best gasoline mileage when running at a steady optimal speed. With grid

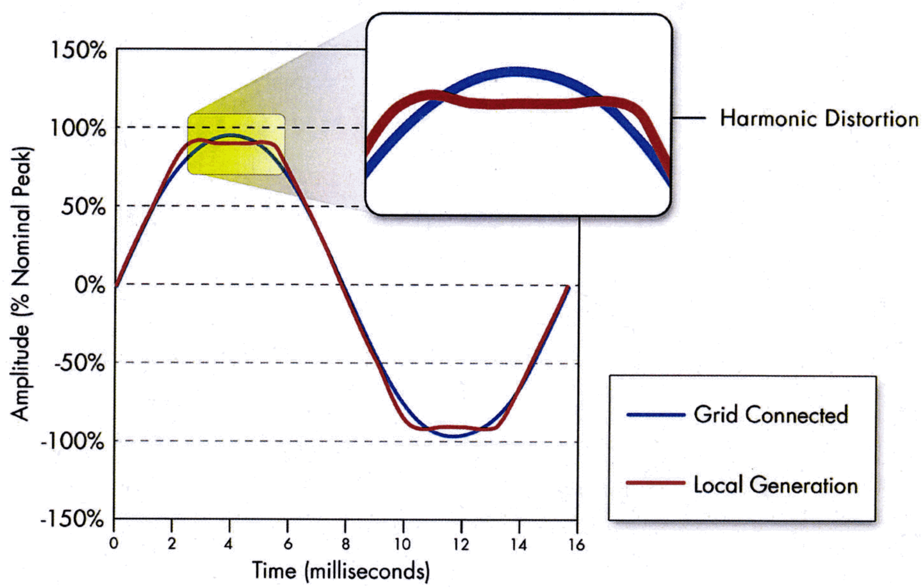

Figure 7: The Grid Delivers High-Quality Power with Minimal Harmonic Distortion.

[11] *Harmonics are voltages or currents that are on the grid, but do not oscillate with the main system frequency (60Hz in the United States). The magnitude of the harmonics, when compared to the magnitude of the 60Hz component, is referred to as the* harmonic distortion.

[12] *Technological improvements are available, such as uninterruptible power supplies (UPS), that reduce the sensitivity of loads to poor power quality, but at an additional cost.*

connectivity, a distributed energy resource can always run at its optimum level without having to adjust its output based on local load variation. Without grid connectivity, the output of a distributed energy resource will have to be designed to match the inherent variation of load demand. This fluctuating output could reduce system efficiency as much as 10%–20% [26].

5. **Energy Transaction** – Perhaps the most important value that grid connectivity provides consumers, especially those with distributed generation, is the ability to install any size DER that can be connected to the grid. A utility connection enables consumers to transact energy with the utility grid, getting energy when the customer needs it and sending energy back to the grid when the customer is producing more than is needed. This benefit, in effect, shifts risks with respect to the size of the energy resource from the individual user to the party responsible for the resources and operation of the grid. Simulated system results for such transactions are provided in Figure 8.

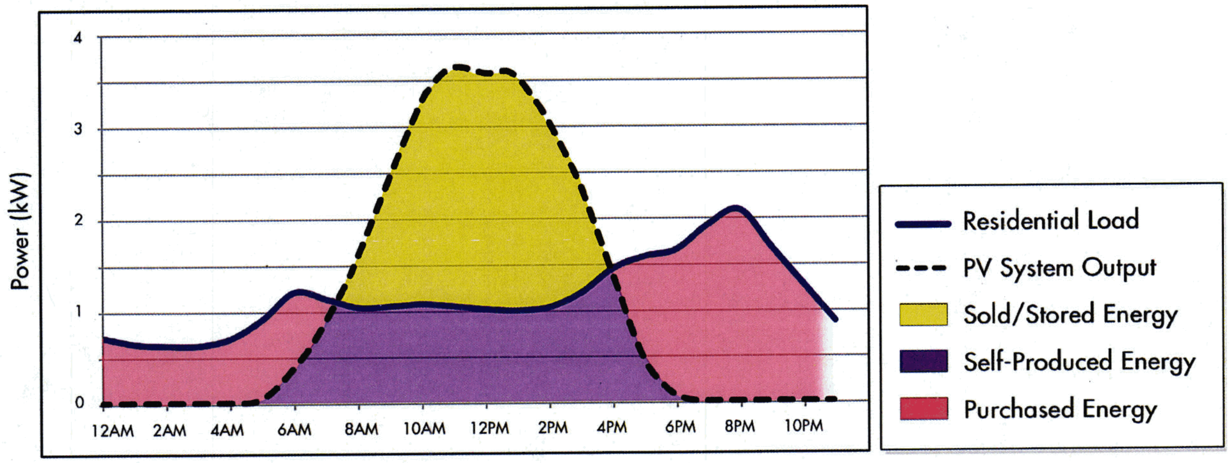

Figure 8: Because Residential Load and PV System Output Do Not Match, Owners of Distributed Generation Need the Grid for Purchasing or Selling Energy Most of the Time.

Cost of Grid Service: Energy and Capacity Costs

For residential customers, the cost for generation, transmission, and distribution components can be broken down as costs related to serve the customer with *energy* (kWh) and costs related to serve the customer with *capacity* that delivers the energy and grid-related services. The five main benefits of grid connectivity discussed in the previous section span both capacity and energy services. Figure 9 shows that, based on the U.S. Department of Energy's *Annual Energy Outlook 2012*, an average customer consumes 982 kWh per month, paying an average bill of $110 per month, with the average cost of $70 for generation of electricity. That leaves $30 for the distribution system and $10 for the transmission system [27]—known together as "T&D". These are average values, and costs vary among and within utilities and across different types of customers. (See *Appendix A* for explanation of calculations in this section.)

The next step in the analysis is to allocate these costs (generation and T&D) into fractions that are relevant for analyzing how the grid works with DER. In this analysis we focus on capacity and grid-related services because they are what enable robust service even for customers with DER. Indeed, consumers with distributed generation may not consume any net energy (kWh) from the grid, yet they benefit from the same grid services as consumers without distributed generation.

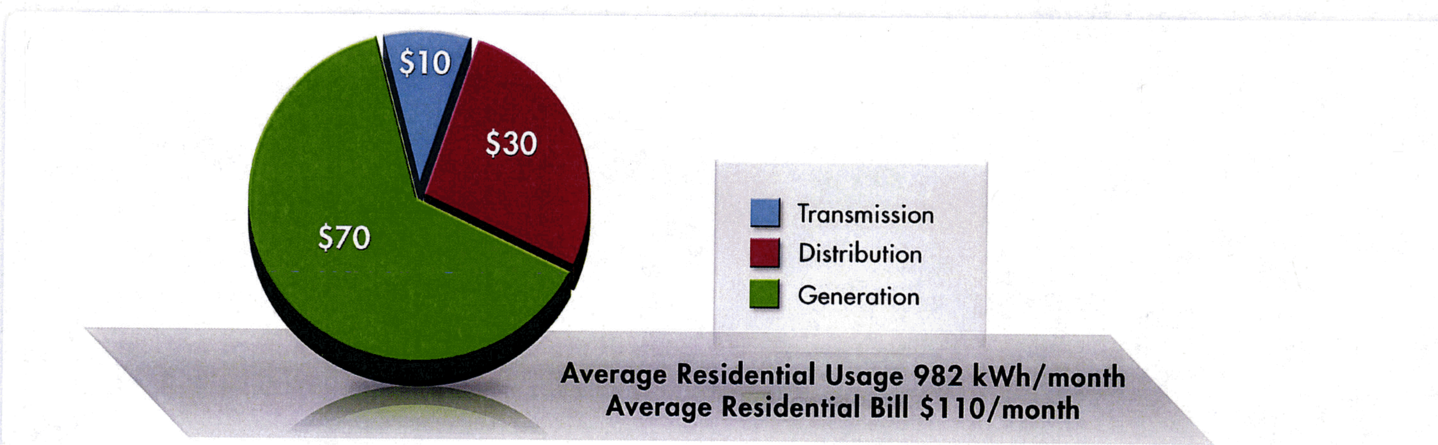

Figure 9: Cost of Service Breakdown for Today's Grid-Connected Residential Customer [27].

Calculating the total cost of capacity follows the analysis summarized in Figure 10. These values are based on the assumption that most costs associated with T&D are related to capacity (except for a small fraction representing system losses—estimated to be $3 per month per customer from recent studies in California) [28]. Working with recent data from PJM [29] regarding the cost of energy, capacity, and ancillary services it is possible to estimate that 80% of the cost of generation is energy related, leaving the rest for capacity and grid services. This 80-20 split will depend on the market and in the case of a vertically integrated utility will depend on the characteristics of the generation assets and load profile, but it is a useful average figure with which some illustrative calculations follow.

As illustrated, the combination of transmission, distribution, and the portion of generation that provides grid support averages $51/month, while energy costs average $59/month. These costs vary widely across the United States and among consumers and also will vary with changes in generation profile and the deployment of new technologies such as energy storage, demand response-supplied capacity, and central generation. The values are shown to illustrate that capacity and energy are both important elements of cost and should be recovered from all customers who use capacity and energy resources. Customers with distributed generation may offset the energy cost by producing their own energy, but as illustrated in previous sections, they still utilize the non-energy services that grid connectivity provides.

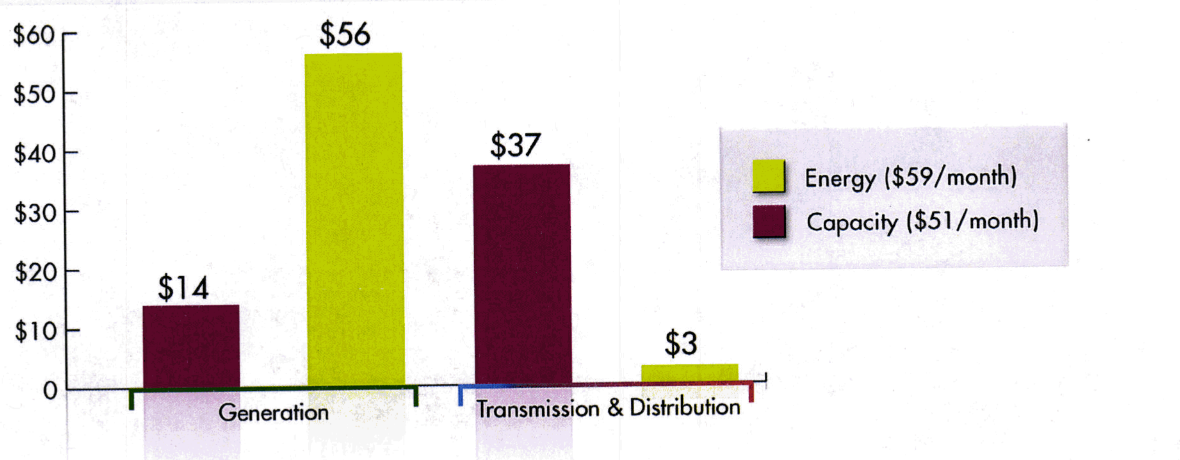

Figure 10: In Considering the Value of the Integrated Grid, Costs of Generation, Transmission, and Distribution Can Be Further Determined for Energy and Capacity.

Cost of Service Without Grid Connectivity

Technologies are available that enable consumers to self-generate and disconnect from the grid. To estimate the capacity-related cost for such investments, a simplified analysis examined a residential PV system. The analysis was based on estimating the additional costs of providing the five services that grids offer—as outlined earlier in this section. For illustration, consider a residential PV system that is completely disconnected from the grid, amortized over 20 years, and presented as a monthly cost. Reinforcing the system for an off-grid application required the following upgrades:

- 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
- Additional operating costs, including inverter replacement and generator maintenance

In simulation, the cost to re-create grid-level service without a grid connection ranges from \$275–\$430 per month *above* that of the original array. Expected decreases in the cost of battery and PV module technology could reduce this to \$165–\$262 within a decade. Further information on this analysis is provided in Appendix A. Costs for systems based on other technologies, or larger deployments such as campus-scale microgrids, could be relatively lower, based on economies of scale. However, even if amortized capital costs are comparable to grid services, such isolated grids will result in deteriorating standards of reliability and quality of electricity service and could require extensive use of backup generators whose emissions negatively impact local air quality.

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Enabling Policy and Regulation

A policy and regulatory framework will be needed to encourage the effective, efficient, and equitable allocation and recovery of costs incurred to transform to an integrated grid. New market frameworks will have to evolve in assessing potential contributions of distributed and central resources to system capacity and energy costs. Such innovations will need to be anchored in principles of equitable cost allocation, cost-effective and socially beneficial investment, and service that provides universal access and avoidance of bypass.

As discussed, the cost of supply and delivery capacity can account for almost 50% of the overall cost of electricity for an average residential customer. Traditionally, residential rate structures are based on metered energy usage. With no separate charge for capacity costs, the energy charge has traditionally been set to recover both costs. This mixing of fixed and variable cost recovery is feasible when electricity is generated from central stations, delivered through a conventional T&D system, and used with an electromechanical meter that measures energy use only by a single entity [30] [31].

Most residential (and some commercial) rate designs follow this philosophy, but the philosophy has not been crisply articulated nor reliably implemented for DER. Consequently, consumers that use distributed resources to reduce their grid-provided energy consumption significantly but remain connected to the grid, may pay significantly less than the costs incurred by the utility to provide capacity and grid connectivity. In effect, the burden of paying for that capacity can potentially shift to consumers without DER [32].

A logical extension of the analysis provided here, as well as many other studies that look at DER under different circumstances, is that as DER deploy more widely, policy makers will need to look closely at clearly separating how customers pay for actual energy and how they pay for capacity and related grid services.

A policy and regulatory framework will be needed to encourage the effective, efficient, and equitable allocation and recovery of costs incurred to transform to an integrated grid.

Realizing the Value of DER Through Integration

The analysis of capacity-related costs (including the cost of ancillary services) in the previous sections is based on today's snapshot of the components that make up the grid and is also based on a minimum contribution from DER to reduce the capacity cost. With increasing penetration of variable generation (distributed and central), it is expected that capacity- and ancillary service-related costs will become an increasing portion of the overall cost of electricity [33].

However, with an integrated grid there is an opportunity for DER to contribute to capacity and ancillary services that will be needed to operate the grid. The following considerations will affect whether and how DER contribute to system capacity needs:

Delivery Capacity – The extent to which DER reduce system delivery capacity depends on the expected output during peak loading of the local distribution feeder, which typically varies from the aggregate system peak. If feeder peak demand occurs after sunset, as is the case with many residential feeders, local PV output can do nothing to reduce feeder capacity requirements. However, when coupled with energy storage resources dedicated to smoothing the intermittent nature of the resources, such resources could significantly reduce capacity need. Similarly, a smart inverter, integrated with a distribution management system, may be able to provide distributed reactive power services to maintain voltage quality.

Supply Capacity – The extent to which DER reduce system supply capacity depends on the output expected during high-risk periods when the margin between available supply from other resources and system demand is relatively small. If local PV production reduces high system loads during summer months but drops significantly in late evening prior to the system peak, it may do little to reduce system capacity requirements. Conversely, even if PV production drops prior to evening system peaks, it may still reduce supply capacity requirements if it contributes significantly during other high-risk periods such as shoulder months when large blocks of conventional generation are unavailable due to maintenance. Determining the contribution of DER to system supply capacity requires detailed analysis of local energy resources relative to system load and conventional generation availability across all periods of the year and all years of the planning horizon.

With an integrated grid there is an opportunity for DER to contribute to capacity and ancillary services.

- **System Flexibility** – As distributed variable generation is connected to the grid, it may also impact the nature of the system supply capacity required. Capacity requirements are defined by the character of the demand they serve. Distributed resources such as PV alter electricity demand, changing the distributed load profile. PV is subject to a predictable diurnal pattern that reduces the net load to be served by the remaining system. At high levels, PV can alter the net load shape, creating additional periods when central generation must "ramp" up and down to serve load. Examples are early in the day when the sun rises and PV production increases and later, as the sun sets, when PV output drops, increasing net load. The net load shape also becomes characterized by abrupt changes during the day, as when cloud conditions change significantly.
- **Integration of DER Deployment in Grid Planning** – Adequacy of delivery and supply capacity are ensured through detailed system planning studies to understand system needs for meeting projected loads. In order for DER to contribute to meeting those capacity needs in the future, DER deployment must be included in the associated planning models. Also, because DER are located in the distribution system, certain aspects of distribution, transmission, and system reliability planning have to be more integrated. (Read more in the section, *Importance of Integrated Transmission and Distribution Planning and Operation for DER.*)
- **DER Availability and Sustainability over the Planning Horizon** – For either delivery or supply capacity, the extent to which DER can be relied upon to provide capacity service and reduce the need for new T&D and central generation infrastructure depends on planners' confidence that the resource will be available when needed across the planning horizon. To the extent that DER may be compensated for providing capacity and be unable or unwilling to perform when called upon, penalties may apply for non-performance.

In addition to altering the system daily load curve, wind and solar generation's unscheduled, variable output will require more flexible generation dispatch. For example, lower cost and generally large and less operationally flexible plants today typically carry load during the day. These resources may have to be augmented by smaller and more flexible assets to manage variability; however, this flexibility to handle fast ramping conditions comes with a cost. [34] [35] The potential for utilizing demand response or storage should not be overlooked, as rapid activation (on the order of seconds or minutes) could provide additional tools for system operators. Improving generator scheduling and consolidating balancing areas could improve access and utilization of ramping resources, preventing the unnecessary addition of less-efficient peaking units [36].

In addition to altering the system daily load curve, wind and solar generation's unscheduled, variable output will require more flexibile generation dispatch.

Figure 11 illustrates the importance of understanding the system to determine the value of DER. The graph shows the German power system's load profile and the substantial impact of PV power generation at higher penetration [37]. In this case, the PV resource's peak production does not coincide with the system peak, and, therefore, does not contribute to an overall reduction in system peak. From the single average plots in Figure 11, it is unclear to what extent PV might contribute to system capacity needs during critical supply hours outside of absolute system peak. During system peak, which for Germany is winter nights, the ~36 GW of installed PV does not contribute to reducing that peak. This is based on the requirements of "reliably available capacity" [38], which is defined as the percentage of installed capacity that is 99% likely to be available.

The ~33 GW of wind is also credited to a minor extent towards meeting the winter peak demand. Hydro power provides the bulk of the 12 GW of renewable resource that is considered as reliable available capacity to meet the 80 GW of winter peak load. However in the United States, where the PV peak coincides more with the system peak (depending on the facility's orientation, shading, and other factors), the results could be different. In general, however, PV without storage to achieve coincidence with system peak will be relatively ineffective in reducing capacity costs due to its variable, intermittent nature.

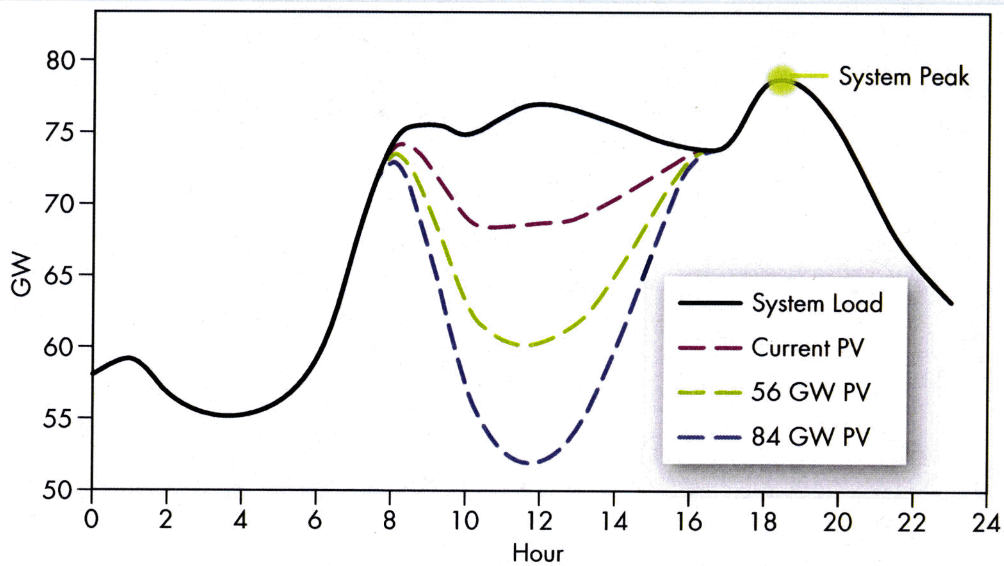


Figure 11: Peak Load Reduction and Ramp Rate Impacts Resulting from High Penetration of PV [39].

Importance of Integrated Transmission and Distribution Planning and Operation for DER

To realize their full value while ensuring power quality and reliability for all customers, DER must be included in distribution planning and operation, just as central generation resources are included in transmission planning and operation. As DER penetration increases and becomes concentrated in specific areas, their impact can extend beyond the distribution feeders to which they are interconnected, potentially affecting the sub-transmission and transmission systems. The aggregated impact of DER must be visible and controllable by transmission operators and must be included in transmission planning to ensure that the transmission system can be operated reliability and efficiently. Additionally, the T&D system operators must coordinate to expose DER owners to reliability needs and associated price signals. This will require significantly expanded coordination among T&D system planners and operators, as well as the development and implementation of new analysis tools, visualization capabilities, and communications and control methods.

Integrated T&D planning methods that include DER are not yet formalized, even in regions with high DER penetration levels such as Germany, Arizona, California, and Hawaii. Without a framework for integration into both T&D system operations, the cost of integration will increase significantly and the potential value of DER will not be fully realized. For example, DER installations in sub-optimal locations, such as the end of long feeders, may require significant feeder upgrades to avoid impacts to voltage quality. When strategically located, however, DER may require little or no upgrade of the feeder while delivering multiple benefits.

Examples of Integration of DER in Distribution Planning and Operations

The Hawaiian Electric Company (HECO) system on the island of Oahu had more than 150 MW of installed distributed PV in mid-2013. At this level of penetration, HECO has found it necessary to develop PV fleet forecasting methods, which it uses to provide operators with geographic information on expected PV output and potential impact on local feeder operations, as well as aggregate impact on system balancing and frequency performance. Additionally, HECO has developed detailed distribution feeder models that incorporate existing and expected future PV deployments for considering PV in planning. Although still in development, HECO is taking these steps to ensure reliability by integrating distributed PV into their operational and planning processes.

To realize their full value while ensuring power quality and reliability for all customers, DER must be included in distribution planning and operation, just as central generation resources are included in transmission planning and operation.

Realizing the importance of planning in DER procurement and operation, regulatory commissions in some cases have decided that distributed resource needs are best served by utility ownership or at least utility procurement of required distributed resources [40], [41]. Competitive procurement often reduces the asset cost while proper planning reduces integration costs and often maximizes the opportunity for capitalizing on multiple potential DER value streams. A recent ruling from the California Public Utilities Commission (CPUC) highlighted this consideration by requiring utilities to procure energy storage, ensuring that these resources are sufficiently planned in the context of the distribution grid [42].

Presently, most DER installations are "invisible" to T&D operators. The lack of coordination among DER owners, distribution operators, and transmission operators makes system operations more difficult, even as system operators remain responsible for the reliability and quality of electric service for all consumers. Likewise, utilities miss an opportunity to use DER, with the proper attributes, to support the grid. The expected services rendered from distributed storage in California are provided in Table 1. However, an integrated grid is required to enable many of these services, making integration beneficial to the entire system, not only to customers who own DER.

Category	Storage "End-Use"
Describes the point of use in the value chain	Describes the use or application of storage
Transmission/Distribution	Peak shaving
	Transmission peak capacity support (upgrade deferral)
	Transmission operation (short-duration performance, inertia, system reliability)
	Transmission congestion relief
	Distribution peak capacity support (upgrade deferral)
	Distribution operation (voltage/VAR support)
Customer	Outage mitigation: micro-grid
	Time-of-use (TOU) energy cost management
	Power quality
	Back-up power

Table 1: Expected T&D and Customer Services from Distributed Storage in California [43].

Realize the Benefits of Distributed Energy Resources

An integrated grid that enables a higher penetration of DER offers benefits to operators, customers, and society. These examples illustrate the diverse nature of these benefits:

- **Provide distribution voltage support and ride-through** – DER can provide distribution grid voltage and system disturbance performance by riding through system voltage and frequency disturbances to ensure reliability of the overall system, provided there are effective interconnection rules, smart inverters, or smart interface systems.
- **Optimize distribution operations** – This can be achieved through the coordinated control of distributed resources and the use of advanced inverters to enhance voltage control and to balance the ratio of real and reactive power needed to reduce losses and improve system stability.
- **Participate in demand response programs** – Combining communication and control expands customer opportunities to alter energy use based on prevailing system conditions and supply costs. Specifically with respect to ancillary services, connectivity and distribution management systems facilitate consumer participation in demand response programs such as dynamic pricing, interruptible tariffs, and direct load control.

Improve voltage quality and reduced system losses – Included in this are improved voltage regulation overall and a flatter voltage profile, while reducing losses.

Reduce environmental impact – Renewable distributed generation can reduce power system emissions, and an integrated approach can avoid additional emissions by reducing the need for emissions-producing backup generation. Also contributing will be the aggregation of low-emissions distributed resources such as energy storage, combined heat and power, and demand response.

Defer capacity upgrades – With proper planning and targeted deployment, the installation of DER may defer the need for capacity upgrades for generation, transmission, and/or distribution systems.

Improve power system resiliency – Within an integrated grid, distributed generation can improve the power system's resiliency, supporting portions of the distribution system during outages or enabling consumers to sustain building services, at least in part. Key to doing this safely and effectively is the seamless integration of the existing grid and DER.

Figure 12 illustrates a concept of an integrated grid with DER in residences, campuses, and commercial buildings networked as a distributed energy network and described in a recent EPRI report [44].

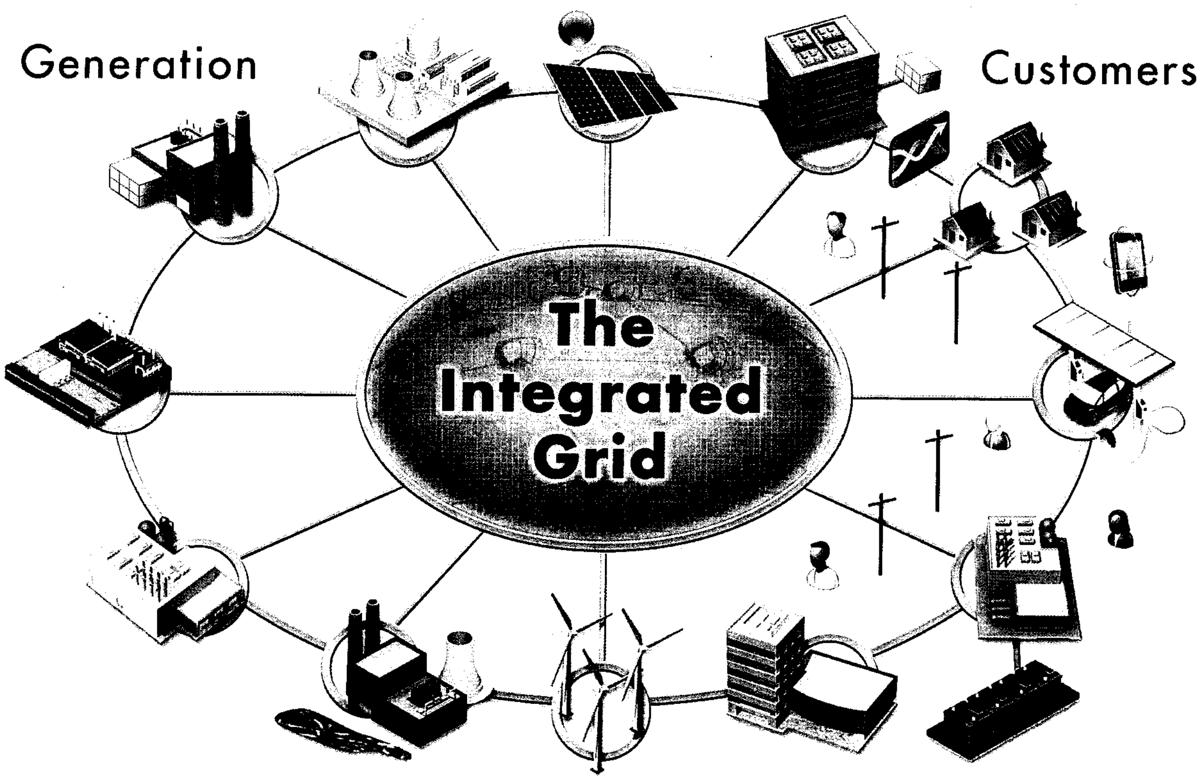


Figure 12: Creating an Architecture with Multi-Level Controller [44].

Grid modernization of the distribution system will include re-conductoring, and augmenting its infrastructure along with deploying smart technologies such as distribution management systems (DMS), communication, sensors, and energy storage is a key component of moving to the Integrated Grid. It is anticipated that this combination of infrastructure reinforcement and smart technology deployment can yield the lowest-cost solution for a given penetration level of DER in a feeder.

Table 2 shows a menu of technology options for the DSO side, the consumer side, and the integration of the two that will enable a distribution feeder to reliably integrate greater DER penetration [45], [46]. The solutions, which have been outlined and evaluated by others in the industry, are organized as follows:

System operator solutions are those actions that the DSO could take to bolster the performance and reliability of the system where DER deployment is growing.

Interactive solutions are those that require close coordination between the system operator and DER owner and generally provide the operator the ability to interact with the DER owner's system to help maintain reliable system operation.

DER owner solutions are those that could be employed at the customer end of the system through installation of technology or operational response measures.

A comprehensive understanding of each approach is beyond the scope of this paper but is an important element of EPRI's proposed work. Assuming that any grid investment will be paid for by customers, it is important to determine if, and under what situations, such investments may prove cost-effective and in the public interest.

The coordinated demonstration of each option outlined in Table 2 across different types of distribution system feeders can help provide a knowledge repository that stakeholders can use to determine the prudence of the various investments needed to achieve an integrated grid. Such demonstrations also can provide information essential for all stakeholders regarding rules of engagement among DER owners, DSOs, TSOs, and ISOs.

No one entity has the resources to conduct the demonstrations and the associated engineering analysis to document costs, benefits, and performance of all technology options across all types of distribution feeders. EPRI proposes using its collaborative approach globally to develop a comprehensive repository of data and information that can be used to move toward the Integrated Grid.

System Operator Solutions	Interactive Solutions	DER Owner Solutions
Network reinforcement	Price-based demand response	Local storage
Centralized voltage control	Direct load control	Self-consumption
Static VAR compensators	On-demand reactive power	Power factor control
Central storage	On-demand curtailment	Direct voltage control
Network reconfiguration	Wide-area voltage control	Frequency-based curtailment

Table 2: Technology Options [45], [46].

Action Plan

The current and projected expansion of DER may significantly change the technical, operational, environmental, and financial characteristics of the electricity sector. An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. Interconnection Rules and Communications Technologies and Standards

   - ***Interconnection rules*** that preserve voltage support and grid management
   - ***Situational awareness*** in operations and long-term planning, including rules of the road for installing and operating distributed generation and storage devices
   - Robust ***information and communication technologies***, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cyber security
   - A ***standard language and a common information model*** to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems

2. Assessment and Deployment of Advanced Distribution and Reliability Technologies

   - ***Smart inverters*** that enable DER to provide voltage and frequency support and to communicate with energy management systems [1]
   - ***Distribution management systems and ubiquitous sensors*** through which operators can reliably integrate distributed generation, storage, and end-use devices while also interconnecting those systems with transmission resources in real time [2]
   - ***Distributed energy storage and demand response***, integrated with the energy management system [3]

3. Strategies for Integrating DER with Grid Planning and Operation

   - ***Distribution planning and operational processes*** that incorporate DER
   - ***Frameworks for data exchange and coordination*** among DER owners, DSOs, and organizations responsible for transmission planning and operations
   - Flexibility to ***redefine roles and responsibilities*** of DSOs and ISOs

4. Enabling Policy and Regulation

   - ***Capacity-related costs*** must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
   - ***Power market rules*** that ensure long term adequacy of both energy and capacity
   - ***Policy and regulatory framework*** to ensure that costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
   - ***New market frameworks*** using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs

Next Steps for EPRI

In order to provide the knowledge, information, and tools that will inform key stakeholders as they take part in shaping the four key areas supporting transformation of the power system, EPRI has begun work on a three-phase initiative.

Phase I – Develop a Concept Paper

This concept paper was developed to align stakeholders on the main issues while outlining real examples to support open fact-based discussion. Input and review was provided by various stakeholders from the energy sector including utilities, regulatory agencies, equipment suppliers, non-governmental organizations (NGOs), and other interested parties. The publication of this paper will be followed by a series of public presentations and additional topical papers of a more technical nature that will more completely analyze various aspects of the Integrated Grid and lessons learned from regions where DER penetration has increased.

Phase II – Develop an Assessment Framework

In this six-month project, EPRI will develop a framework for assessing the costs and benefits of combinations of technology that lead to an integrated grid. Such a framework is required to ensure consistency in the comparison of options and to build a resource library that will inform the Phase III demonstration program.

In order to organize a comprehensive framework, EPRI will analyze system operator, DER owner, and interactive options listed in Table 2. Since each country, state, region, utility, and feeder may have differing characteristics that lead to different optimized solutions, efforts will be made to ensure that the framework is flexible enough to accommodate these differences.

Additionally, a testing protocol will be developed in support of the Phase III global demonstration program to ensure that a representative sample of systems and solutions will be tested.

Phase III – Conduct a Global Demonstration and Modeling Program

Phase III will focus on conducting global demonstrations and modeling using the analytics and procedures developed in Phase II to provide data and information that stakeholders will need for the system-wide implementation of integrated grid technologies in the most cost-effective manner.

Using the Phase II framework and resource library, participants in Phase III can combine and integrate their various experiments and demonstrations under a consistent protocol. However, it is neither economic nor practical for an individual DSO to apply all the technological approaches across different types of distribution circuits. Therefore, Phase III, planned as a two-year effort, will present the opportunity for utilities globally to collaborate to assess the cost, benefit, performance, and operational requirements of different technological approaches to an integrated grid.

Demonstrations and modeling projects in areas where DER deployment is not expected near term will use the analytics and procedures developed in Phase II to ensure that results can provide data and information that utilities will need for planning investments in the system-wide implementation of integrated grid technologies.

With research organizations and technology providers working with distribution companies on individual demonstration projects, EPRI can work to ensure that findings and lessons learned are shared, and to consolidate the evaluations of the different approaches. The lessons learned from the real life demonstrations will be assembled in a technology evaluation guidebook, information resources, and analysis tools.

New technologies for grid modernization will continue to evolve as the transformation to an integrated grid continues in this decade and beyond. The effort outlined in Phase II and Phase III will not be a one-time event but will set the stage for ongoing technology development and optimization of the integrated grid concept. As new technology evolves, a comprehensive framework for assessment of the technology as outlined in Phases II and III can support prudent investment for grid modernization using solid scientific assessment before system-wide deployment.

An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration.

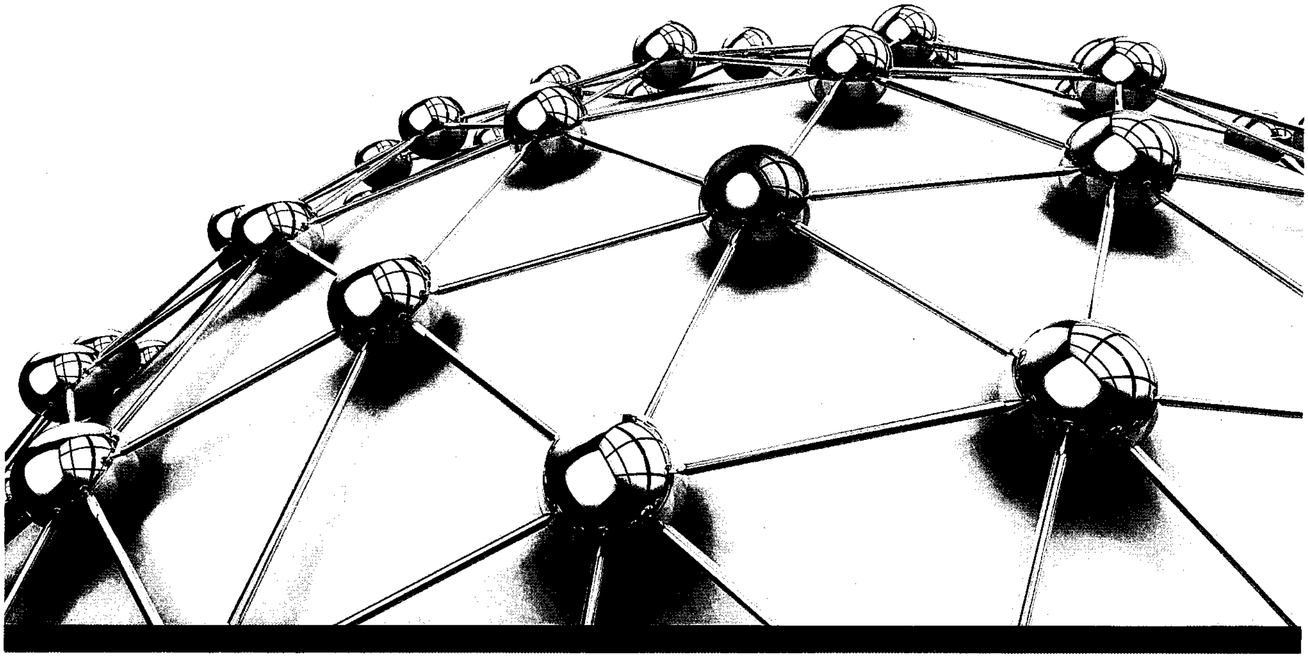
Outputs from the Three-Phase EPRI Initiative

Taken together, Phases II and III will help identify the technology combinations that will lead cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. Also to be developed are interface requirements that help define the technical basis for the relationship between DER owners, DSOs, and TSOs or ISOs. The information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system and inform policymakers and regulators as they implement enabling policy and regulation. The development of a consistent framework backed up with data from a global technology demonstration and modeling program will support cost-effective and prudent investments to modernize the grid in order to effectively integrate large amounts of DER into the existing power system.

A key deliverable from the Phase II and III efforts will be a comprehensive guidebook, analytical tools, and a resource library for evaluating combinations of technologies in distribution system circuits. In order to maximize the value of these deliverables, EPRI will seek to partner with organizations that are leading integrated grid-style analyses and demonstration projects to ensure that all have access to the full database of inputs and outputs from these important projects even if they were not directly involved in the technical work. Key components of the guidebook, analytical tools, and resource library will include:

- Comprehensive descriptions of technological approaches and how they can be applied in a distribution system
- Modeling tools and approaches required to assess the performance of the technical solutions
- Operational interface that will be required between DER owners and DSOs
- Analytics to assess the hosting capacity of distribution circuits
- Analytics to evaluate technology options and costs to support greater penetration of DER
- Analytics to characterize the value of integrated grid approaches beyond increasing feeder hosting capacity

A collaborative approach will be essential to develop the comprehensive knowledge repository of costs, benefits, performance, and operational requirements of the multitude of technical approaches that can be implemented in a given distribution feeder for a specific level of DER integration. The guidebook, analytical tools, and resource library will build on prior work of EPRI and other research organizations to develop a portfolio of solution options outlined in Table 2. They will also use the DOE/EPRI cost/benefit framework for evaluating smart grid investments as part of smart grid demonstrations around the world [47].



Conclusion

Changes to the electric power system with the rise of DER have had a substantial impact on the operation of the electric power grid in places such as Germany and Hawaii. As consumers continue to exercise their choice in technology and service, as technologies improve in performance and cost, and as federal and regional policy incentives are passed, DER could become even more pervasive.

DER deployment may provide several benefits, including reduced environmental impact, deferred capacity upgrades, optimized distribution operations, demand response capabilities, and improved power system resiliency. The successful integration of DER depends pivotally on the existing electric power grid, especially its distribution systems, which were not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. Certain types of DER operate with more variability and intermittency than the central power stations on which the existing power system is based. The grid provides support that balances out the variability and intermittency while also providing other services that may be difficult to replicate locally.

An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. **Interconnection Rules and Communications Technologies and Standards**
2. **Assessment and Deployment of Advanced Distribution and Reliability Technologies**
3. **Strategies for Integrating DER with Grid Planning and Operation**
4. **Enabling Policy and Regulation**

In order to provide the knowledge, information, and tools that will inform key stakeholders as they take part in shaping the four key areas supporting transformation of the power system, EPRI has begun work on a three-phase initiative:

- Phase I – Align stakeholders with a concept paper (this document).
- Phase II – Develop a framework for assessing the costs and benefits of combinations of technology that lead to an integrated grid.
- Phase III – Initiate a worldwide demonstration program to provide data to those seeking to implement integrated grid solutions.

The initiative will help identify the technology combinations that will lead to cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. It will develop interface requirements to help define the technical basis for the relationship between DER owners, DSOs, and TSOs or ISOs. Finally, the information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system while supporting the robust evaluation of the capacity and energy contribution from both central and distributed resources.

The development of a consistent framework supported by data from a global technology demonstration and modeling program will support cost-effective and prudent investments to modernize the grid and the effective, large-scale integration of DER into the power system. The development of a large collaborative of stakeholders will help the industry move in a consistent direction to achieve an integrated grid.

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Generation, Transmission, and Distribution vs. Cost of Energy and Capacity

Generation, transmission, and distribution breakdowns are provided from EIA estimates in ($/kWh), assuming an average customer usage of 982 kWh/month.

Generation is broken into two components (energy and capacity) based on PJM market estimates of the price breakdown: "2010 PJM Market Highlights: A Summary of Trends and Insights." 2011.

Of which, 80% was estimated as energy related, while the other 20% was attributed to capacity.

Distribution and transmission are estimated based on the following breakdown from SCE (E3 NEM Effectiveness Report):

Among the appendices, Southern California Edison's (SCE's) implied transmission and distribution (T&D) costs were provided. When those costs were scaled back to national average values, the percentages are provided below:

SCE Implied Cost breakdowns (when scaled to $40/month)

Cost Breakdown	$/Month	Fixed %	Variable %	Fixed ($)	Variable ($)
Customer	$14.29	100%	0%	$14.29	$–
Distribution	$15.71	90%	10%	$14.14	$1.57
Sub-transmission	$4.29	60%	40%	$2.57	$1.71
Transmission	$5.71	100%	0%	$5.71	$–
TOTAL	$40.00			$36.71	$3.29

Thus the variable (energy-based) T&D costs were taken at $3/month.

Cost of Off-Grid Residential Solutions

Cost figures reflect the additional cost to take a residence that produces 100% of its energy locally (from PV) and turn it into a self-sufficient entity that can operate without a grid connection.

These costs include the following, which are then amortized across the lifetime of the project (20 years):

Extra PV panels (beyond the annual kWh requirement)
Battery storage
Charge controller
Backup generator

Software Package: HOMER Energy (Hourly energy profile simulator)
Locations: St. Louis, MO and San Francisco, CA
Analysis includes appropriate incentives Federal ITC and net-energy-metering

Location	St. Louis, MO	San Francisco, CA
Load Profile (OpenEI)	12MWh/yr	7.67MWh/yr
Real Interest Rate	3.5% (5.5% APR – 2% inflation)	
Project Lifetime	20 years (no salvage)	
PV System (Array + Inverter) Installed Cost	\$3-\$4/W installed (after incentive) [2013] \$1.50-\$2/W installed [2020]	
Battery Cost	\$450-\$550/installed kWh [2013] \$200-\$300/installed kWh [2020]	
Generator	\$400/kW	
System Controller	\$600/kW	
System O&M	\$32/kW/yr PV system O&M + \$0.50/hr generator O&M + \$3/battery/yr	

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent approximately 90 percent of the electricity generated and delivered in the United States, and international participation extends to more than 30 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy for approval of a cost-of-service study and net metering tariffs.	)	Docket No. 15-07041
Application of Sierra Pacific Power Company d/b/a NV Energy for approval of a cost-of-service study and net metering tariffs.	)	Docket No. 15-07042

At a general session of the Public Utilities Commission of Nevada, held at its offices on February 12, 2016.

PRESENT: Chairman Paul A. Thomsen
Commissioner Alaina Burtenshaw
Commissioner David Noble
Assistant Commission Secretary Trisha Osborne

MODIFIED FINAL ORDER

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EXHIBIT
APS-11
judicial notice

APS EXHIBIT 11

DOCUMENT REVIEW AND APPROVAL ROUTING

[illegible] BY: DSN

FINAL DRAFT ON 2 / 12 / 16 AT 5 : 00 PM

REVIEWED & APPROVED BY: DATE

☐ ADMIN / ASST.

☑ [illegible] / COUNSEL HW/GW 2 / 17 / 16

☐ SECRETARY / ASST. SEC.

☐ OTHER

TABLE OF CONTENTS

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

Nevada Power Company d/b/a NV Energy ("NPC") filed an Application for approval of a cost-of-service study and net energy metering ("NEM") tariffs. Sierra Pacific Power Company d/b/a NV Energy ("SPPC," and together with NPC, "NV Energy") filed an Application for approval of a cost-of-service study and NEM tariffs.

II. SUMMARY

The Applications are granted as modified in the discussion and findings below. The Commission revises tariffs and rates for NPC and SPPC.

III. PROCEDURAL HISTORY

- On July 31, 2015, NPC filed an Application for approval of a cost-of-service study and NEM tariffs.

- On July 31, 2015, SPPC filed an Application for approval of a cost-of-service study and NEM tariffs.

- The Applications were filed pursuant to the Nevada Revised Statutes ("NRS") and Nevada Administrative Code ("NAC") Chapter 703 and 704, including but not limited to Section 4.5 of Senate Bill ("SB") 374 of the 78th Session of the Nevada Legislature (2015) and NAC 703.535.

- On August 3, 2015, the Commission issued Notices of Application in Docket Nos. 15-07041 and 15-07042.

- The Regulatory Operations Staff ("Staff") of the Commission participates as a matter of right pursuant to NRS 703.301.

- On August 4, 2015, the Attorney General's Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to NRS 228.360 in Docket Nos. 15-07041 and 15-07042.

- On August 14, 2015, the Sierra Club filed a Petition for Leave to Intervene ("PLTI") in Docket Nos. 15-07041 and 15-07042.

- On August 17, 2015, the Alliance for Solar Choice ("TASC") filed a PLTI in Docket Nos. 15-07041 and 15-07042.

- On August 17, 2015, Bombard Renewable Energy ("Bombard") filed a PLTI in Docket No. 15-07041.

- On August 17, 2015, Travis G. Miller filed a PLTI in Docket No. 15-07042.

• On August 17, 2015, Nevadans for Clean Affordable Reliable Energy ("NCARE") filed a PLTI in Docket Nos. 15-07041 and 15-07042.

• On August 17, 2015, the Southern Nevada Homebuilders Association ("SNHBA") filed a PLTI in Docket Nos. 15-07041 and 15-07042.

• On August 17, 2015, the United States Green Building Council, Nevada Chapter ("USGBC") filed a PLTI in Docket No. 15-07041.

• On August 17, 2015, Vote Solar filed a PLTI in Docket Nos. 15-07041 and 15-07042.

• On August 18, 2015, Shawn O'Meara (on behalf of SUNworks, Black Rock Solar, Inc., The Power Company, and Alternative Energy Solutions) filed a late-filed PLTI in Docket No. 15-07042.

• On August 18, 2015, the Solar Energy Industries Association ("SEIA") filed a late-filed PLTI in Docket No. 15-07042.

• On August 18, 2015, the Washoe County School District ("WCSD") filed a PLTI in Docket No. 15-07042.

• On August 19, 2015, the Commission held a prehearing conference. BCP, Bombard, Mr. Miller, NCARE, NV Energy, SEIA, SNHBA, Staff, TASC, USGBC, Vote Solar, and WCSD made appearances. The Presiding Officer excused the Sierra Club and Mr. O'Meara from appearing. The Presiding Officer consolidated Docket Nos. 15-07041 and 15-07042 for hearing purposes. The Presiding Officer granted the PLTIs filed by Bombard, NCARE, TASC, Vote Solar, and WCSD. The Presiding Officer conditionally granted the PLTIs filed by Mr. O'Meara, SEIA, Sierra Club, SNHBA, and USGBC, subject to those parties filing supplemental information. The Presiding Officer denied the PLTI filed by Mr. Miller.

• On August 19, 2015, the Sierra Club filed a Reply to Staff Response to Petition to Intervene in Docket Nos. 15-07041 and 15-07042.

• On August 20, 2015, the Great Basin Solar Coalition ("GBSC"), formerly Mr. O'Meara, filed supplemental information in Docket No. 15-07042.

• On August 20, 2015, SEIA filed a Supplement to Late-Filed Petition for Leave to Intervene in Docket Nos. 15-07041 and 15-07042.

• On August 20, 2015, SNHBA filed a Supplement to the Petition for Leave to Intervene in Docket Nos. 15-07041 and 15-07042.

• On August 20, 2015, USGBC filed a letter rescinding its PLTI in Docket No. 15-07041.

• On August 20, 2015, Vote Solar filed a Supplemental and Errata Filing in Support of Vote

Solar's Petition for Leave to Intervene in Docket Nos. 15-07041 and 15-07042.

• On August 21, 2015, the Commission held a hearing in Docket Nos. 15-07041 and 15-07042. BCP, Bombard, GBSC, NCARE, NV Energy, SEIA, Sierra Club, SNHBA, Staff, TASC, and Vote Solar made appearances.

• On September 1, 2015, the Commission issued an Interim Order.

• On September 4, 2015, the Presiding Officer issued a Procedural Order establishing a procedural schedule in Docket Nos. 15-07041 and 15-07042.

• On October 26, 2015, the Presiding Officer held a discovery conference with NV Energy and TASC.

• On October 28, 2015, the Presiding Officer issued Procedural Order No. 2.

• On November 2, 2015, NV Energy and Vote Solar notified the Presiding Officer, via electronic mail to the Administrative Attorney, of an agreement to revise the procedural schedule as it pertains to work papers.

• On November 6, 2015, Sierra Club submitted a letter requesting to withdraw as a party and participate as a commenter.

• On November 12, 2015, the Presiding Officer issued Procedural Order No. 3.

• On November 18-20, 2015 the Commission held a continued hearing in Docket Nos. 15-07041 and 15-07042. BCP, Bombard, GBSC, NCARE, NV Energy, SEIA, SNHBA, Staff, TASC, Vote Solar, and WCSD made appearances. Exhibits 1A-102A were admitted to the record pursuant to NAC 703.730.

• On December 1, 2015, the Presiding Officer issued Procedural Order No. 4.

• On December 2, 2015, BCP, NCARE, NV Energy, SEIA, Staff, TASC, and Vote Solar filed legal briefs. On December 9, 2015, BCP, NCARE, NV Energy, Staff, TASC, and Vote Solar filed reply briefs.[1]

• At the December 22, 2015 Agenda meeting, the Commission voted to approve the Draft Order. The Commission issued the Final Order on December 23, 2015 ("December 23rd Order").

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[1] Several parties also included analyses of SB 374 and the relevant statutes and regulations in witness testimony. (See Ex. 29A (NV Energy) at 15-17; Ex. 30A (NV Energy) at 15-17; Ex. 40A (WCSD) at 3; Ex. 41A (SNHBA) at 3-4; Ex. 44A (Vote Solar) at 7-9, 11, 13, 46-47, 50-51, 60, 62; Ex. 49A (TASC) at 6-7, 9-10; Ex. 62A (BCP) at 2; Ex. 64A (Staff) at 3, 11-12, 23-24; Ex. 76A (TASC) at 34, 48; Ex. 99A (NV Energy) at 5, 7-15, 79; Ex. 101A (NV Energy) at 6-7, 21-23, 26-31, 35-37, 39, 41-42; Tr. at 89-90 (NV Energy), 99-100 (NV Energy), 357-359 (TASC), 406 (Bombard), 442-443 (BCP), 474-477 (Staff), 503-505 (Staff), 552-554 (Staff), 580-583 (Staff), 595-596 (Staff), 1103-1104 (NV Energy), 1132-1133 (NV Energy), 1140-1144 (NV Energy).)

• On December 24, 2015, BCP filed a Motion for Stay and Request for Order Shortening Time for Responses. On December 29, 2015, BCP filed an Amendment to Motion for Stay and Request for Order Shortening Time for Responses and Request for Modification of Procedural Order No. 5. On December 29, 2015, BCP filed a Corrected Amendment.

• On December 24, 2015, TASC filed a Motion for Stay of Final Order and Tariffs and Request for Order Shortening Time. On December 30, 2015, TASC filed an Amendment to Motion for Stay of Final Order and Tariffs and Request for Order Shortening Time and Request for Modification of Procedural Order No. 5.

• On December 28, 2015, the Presiding Officer issued Procedural Order No. 5, establishing an expedited timeframe for filing responses and replies to the Motions for Stay and a hearing date.

• On December 29, 2015, SNHBA filed a Response to BCP's Motion to Stay. On December 30, 2015, Vote Solar and SEIA filed Responses to the Motions for Stay. On January 4, 1016, NCARE, NV Energy, and Staff filed Responses to the Motions for Stay. On January 6, 2016, BCP and TASC filed Replies.

• On December 31, 2015, the Presiding Officer issued Procedural Order No. 6, suspending GBSC's representative, Shawn O'Meara, from further participation in these proceedings.

• On January 7, 2016, the Commission held a hearing on the Motions for Stay. BCP, Bombard, GBSC, NV Energy, SEIA, SNHBA, Staff, TASC, and Vote Solar made appearances. NCARE and WCSD were excused.

• On January 8, 2016, the Presiding Officer issued Procedural Order No. 7, requiring NV Energy to file notification that it has updated its website with customer education explaining the December 23rd Order.

• On January 8, 2016, BCP filed a Petition for Reconsideration and/or Rehearing,

• On January 8, 2016, SNHBA filed a Petition for Rehearing and Reconsideration.

• On January 8, 2016, SEIA filed a Petition for Reconsideration.

• On January 8, 2016, TASC filed a Petition for Reconsideration.

• On January 8, 2016, Vote Solar filed a Petition for Reconsideration.

• On January 13, 2016, GBSC late-filed a Petition for Reconsideration.[2]

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[2] Pursuant to NAC 703.530(3), the Commission will liberally construe the pleadings and disregard any defects that do not affect the substantial rights of any party. GBSC's late-filed Petition for Reconsideration affects the substantial rights of all other parties because it responds to the Petitions for Reconsideration filed on or before the deadline prescribed in NAC 703.801(3). The Commission construes GBSC's late-filed Petition for Reconsideration as an Answer to the Petitions for Reconsideration.

• On January 19, 2016, the Commission issued an Order, denying the Motions to Stay.

• On January 20, 2016, the Presiding Officer issued a draft Order on BCP's Petition for Reconsideration and/or Rehearing, granting rehearing on grandfathering, and SNHB's Petition for Rehearing and Reconsideration, denying rehearing.

• On January 21, 2016, BCP filed a letter withdrawing the rehearing portion of its Petition for Reconsideration. On January 22, 2016, BCP filed a supplement to its letter.[3]

• On January 22, 2016, SNHBA filed an Errata to its Petition for Rehearing and Reconsideration, removing all references to rehearing.

• On January 22, 2016, SNHBA filed a letter with the Commission regarding the draft Order.[4]

• On January 22, 2016, TASC filed a letter with the Commission regarding the draft Order.[5]

• On January 25, 2016, NV Energy filed an Answer to Petitions for Rehearing.

• On January 25, 2016, BCP, NV Energy, NCARE, Staff, and TASC filed Answers to the Petitions for Reconsideration.

• On January 25, 2016, GBSC filed an Answer to Petitions for Reconsideration. On January 26, 2015, GBSC filed an Amendment.[6]

• On January 25, 2016, the Commission issued an Order to conduct a rehearing in Docket Nos. 15-07041 and 15-07042 to allow the parties to present additional evidence on grandfathering.

• On January 25, 2016, the Commission issued a Notice of Hearing.

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[3] Pursuant to NAC 703.530(3), the Commission will liberally construe the pleadings and disregard any defects that do not affect the substantial rights of any party. Portions of BCP's letter and supplement to the letter affect the substantial rights of all other parties because they respond to the draft Order issued by the Presiding Officer on January 20, 2016. There is no regulation allowing a party to comment on a draft order filed by a commissioner. The portions of the letter and supplement that respond to the draft Order (beyond withdrawing the request for rehearing) are impermissible and, therefore, are stricken from the record.

[4] Pursuant to NAC 703.530(3), the Commission will liberally construe the pleadings and disregard any defects that do not affect the substantial rights of any party. SNHBA's letter affects the substantial rights of all other parties because it responds to the draft Order issued by the Presiding Officer on January 20, 2016. There is no regulation allowing a party to comment on a draft order filed by a commissioner. The letter is a fugitive document and, therefore, is stricken from the record.

[5] Pursuant to NAC 703.530(3), the Commission will liberally construe the pleadings and disregard any defects that do not affect the substantial rights of any party. TASC's letter affects the substantial rights of all other parties because it responds to the draft Order issued by the Presiding Officer on January 20, 2016. There is no regulation allowing a party to comment on a draft order filed by a commissioner. The letter is a fugitive document and, therefore, is stricken from the record.

[6] On February 1, 2016, GBSC filed the same information as supplemental direct testimony.

• On January 27, 2016, Staff filed a Motion to Strike New Evidence Presented in GBSC's Answer to Petitions for Reconsideration and Amendment Thereto.[7]

• On January 28, 2016, Vote Solar filed a letter responding to Staff's Answer to Petitions for Reconsideration, attempting to explain why the Commission should not suspend Vote Solar's representatives from further participation in these proceedings for the misrepresentations in its Petition for Reconsideration.

• On January 28, 2016, TASC filed a Motion for Extended Procedural Schedule Regarding Rehearing. On January 29, 2016, TASC filed an Errata. On January 29, 2016, NV Energy filed a Response. On February 2, 2016, TASC filed a Reply. On February 8, 2016, the Presiding Officer denied the Motion.

• On February 1, 2016, NV Energy filed a Motion to Strike Portions of "Answers" to Petitions for Reconsideration. On February 8, 2016, BCP and TASC filed Responses.[8]

• On February 1, 2016, SNHBA filed a Response to PUC's January 25, 2016, Order.[9]

• On February 2, 2016, TASC filed a Motion Requesting Adequate Public Notice of Proposed Rate Adjustment. On February 3, 2016, NV Energy and Staff filed Responses. On February 8, TASC provided an oral Reply. On February 8, 2016, the Presiding Officer denied the Motion.

• On February 2, 2016, Staff filed a Motion to Strike Portions of the Supplemental Direct Testimonies Filed On Behalf of Vote Solar, GBSC and BCP. On February 4, 2016, Vote Solar filed a Response. On February 5, 2016, NV Energy filed a Joinder in Staff's Motion. On February 5, 2016, BCP filed a Response to Staff's Motion. On February 5, 2016, BCP filed a Response to NV Energy's Joinder. On February 8, 2016, TASC filed a Response. On February 8, 2016, GBSC provided an oral Response. On

[7] The Commission grants Staff's Motion to Strike New Evidence Presented in GBSC's Answer to Petitions for Reconsideration and Amendment Thereto. GBSC filed the same information as supplemental direct testimony on February 1, 2016, asserting that Staff's Motion was rendered moot by the filing. However, GBSC did not withdraw its Answer and Amendment filed on January 25 and 26, 2016. GBSC attempts to impermissibly introduce new evidence, ignoring the fact that the Commission takes evidence through a formal hearing process that guarantees due process to all parties involved.

[8] The Commission grants NV Energy's Motion to Strike Portions of "Answers" to Petitions for Reconsideration. GBSC attempts to impermissibly introduce new evidence, ignoring the fact that the Commission takes evidence through a formal hearing process that guarantees due process to all parties involved. The Commission notes that GBSC's Answer was also the subject of Staff's Motion to Strike New Evidence Presented in GBSC's Answer to Petitions for Reconsideration and Amendment Thereto; the Commission granted Staff's Motion (*see* footnote 7). TASC's arguments starting at page 1, line 18, through page 6, line 3, are an improper attempt to address the Commission's January 19, 2016, Order that is not subject to the Petitions for Reconsideration. BCP's counterarguments at page 4, lines 3-14, are in response to hypothetical arguments that no party made in the Petitions for Reconsideration. All are impermissible answers to the Petitions for Reconsideration.

[9] Pursuant to NAC 703.530(3), the Commission will liberally construe the pleadings and disregard any defects which do not affect the substantial rights of any party. SNHBA's filing affects the substantial rights of all other parties because it responds to the Order in a manner not prescribed by the Commission's regulations. The filing is a fugitive document and, therefore, is stricken from the record.

February 8, 2015, Staff and NV Energy provided oral Replies. On February 8, 2016, the Presiding Officer granted in part and denied in part the Motion and Joinder.

• On February 5, 2016, BCP filed a Legal Brief in Lieu of Rebuttal on Particular Issue Raised by Regulatory Operations Staff. On February 8, 2016, the Presiding Officer struck the document from the record.

• On February 8, 2016, the Commission held a rehearing. BCP, Bombard, GBSC, NCARE, NV Energy, SEIA, Staff, TASC, Vote Solar, and WCSD made appearances. SNHBA was excused. Exhibits 103A-137A were admitted into the record pursuant to NAC 703.730.

IV. COST-OF-SERVICE STUDIES

NV Energy Position

1. NV Energy recommends that the Commission approve the marginal cost-of-service studies ("MCSS") prepared for NPC and SPPC and find that the MCSS are appropriate for designing rates for classes of customer-generators ("NEM ratepayers").[10] (Ex. 1A at 18; Ex. 4A at 18.)

2. NV Energy states that while it is appropriate to develop NEM ratepayer classes for all sizes of NEM ratepayers, NV Energy limited the MCSS and the new NEM tariffs to those classes that are not currently subject to more cost-based pricing (e.g., time-of-use ("TOU") demand charges, facilities charges). For NPC, the affected ratepayer classes are the single family residential ("RS"), multi-family residential ("RM"), large single family residential ("LRS"), and small general service ("GS") classes. For SPPC, the affected ratepayer classes are the single-family residential ("D-1"), multi-family residential ("DM-1"), and small general service ("GS-1") classes. The rate structures for the larger ratepayer classes have cost-based

[10] NEM ratepayers who have completed applications that were accepted or approved by NV Energy prior to the cumulative capacity of all NEM systems reaching the 235 megawatts ("MW") are referred to as NEM1 ratepayers. NEM ratepayers who have completed applications that were accepted or approved by NV Energy after the cumulative capacity of all NEM systems reaching the 235 MW are referred to as NEM2 ratepayers.

customer and facility distribution charges and recover a significant portion of the transmission and generation costs through TOU demand charges. (Ex. 2A at 26; Ex. 5A at 26.)

3. NV Energy states that the MCSS guides the development of each ratepayer class's total revenue requirement and rate design. The MCSS develops the revenues at full marginal costs that would be realized if hourly differentiated prices equal to NV Energy's marginal costs were charged to each ratepayer class. Through Statement O, the ratepayer class marginal revenues are used to allocate the embedded revenue requirement to the various classes. (Ex. 2A at 26, 46-47, 164-167; Ex. 5A at 26, 46-47, 158, 160.)

4. The MCSS demonstrate that NEM ratepayers have unique service and cost characteristics. The average NEM ratepayer and non-NEM ratepayer have distinctly different load shapes, load factors, and billing determinants. The load levels and hourly usage differences (let alone the partial-requirements nature of their service) are sufficient to justify separate rate classes. Further, the ability for the NEM ratepayers to flow energy back into the utility systems is something NV Energy does not allow larger partial-requirements (stand-by) ratepayers to do. The result is a substantial cost shift from NEM ratepayers to non-NEM ratepayers. (Ex. 2A at 11, 21, 33-35, 163, 177-184, 187; Ex. 5A at 11, 21, 32-35, 162, 166-172, 174; Tr. at 167-168.)

5. NV Energy states that while the MCSS redistributed the revenue requirement to all ratepayer classes, no other ratepayer class rate changes are being proposed. The sole objective of the Applications is to establish NEM ratepayer classes and rates based on the MCSS. NV Energy prepared the MCSS consistent with: (1) the Commission's regulations; (2) NV Energy practices that have evolved over 30 years; (3) previous MCSS that have been vetted and approved in the past by the Commission; and (4) the presentation made by NV Energy at the

May 1, 2015, workshop in Docket No. 14-06009. (Ex. 2A at 9-10, 14, 16, 25, 46; Ex. 5A at 9-10, 14, 16, 25, 46.)

6. NV Energy states that it updated numerous inputs for the MCSS. NV Energy updated the marginal energy cost and hourly loss of load probability, which is used in the marginal generation cost allocation. NV Energy used the PROMOD results to reflect NPC's integrated resource plan filing (Docket No. 15-07004) preferred plan. NPC's integrated resource plan filing PROMOD results are used for both NPC and SPPC for marginal energy costs due to joint dispatching. The marginal energy costs cover the period 2016-2018, which is the potential rate effective period. NPC's and SPPC's loss of load probabilities are determined separately because neither utility's resources can prevent a loss of load occurrence for the other utility. The hourly loss of load probability is the hourly cost responsibility factor used to spread generation unit demand costs to each ratepayer class. The loss of load probability data was for the period prior to the forecasted significant capacity addition in 2020 (i.e., 2016-2019). NV Energy updated the probability of system peak cost responsibility factor used in the ratepayer class allocation of distribution demand and transmission costs. NV Energy also updated the historical ten-year period data to 2005-2014 and the forecasted period year to 2016. NV Energy updated NPC's rate of return to reflect the authorized rate in the Docket No. 14-05004 Stipulation. NV Energy used the billing determinants for the twelve-month period that ended May 2014 for NPC and the twelve-month period that ended March 2015 for SPPC. The NEM2 class load shapes were developed for the twelve months ended May 2015 and were removed from the otherwise full requirements class. The Customer Weighing Factor Study ("CWFS") was updated to include the new NEM classes. New surveys of the pertinent departments serving NEM ratepayers were made to determine the relative proportion of customer service and accounts

expense attributable to the separate NEM ratepayer classes. (Ex. 2A at 26-28, 35, 38, 63; Ex. 5A at 26-27, 35, 38, 60-61, 68.)

7. NV Energy states that the MCSS have four functional components: facilities; customer; demand-related (non-revenue distribution feeders, substations, transmission, and generation); and energy. Other than facilities and customer costs, the marginal costs are determined using hourly data, developed from PROMOD outputs and historical data. Additionally, facilities and customer costs are recovered through the monthly basic service charge. (Ex. 2A at 26, 31-32; Ex. 5A at 26, 30, 32.)

8. NV Energy states that the facilities costs represent NV Energy's investment in distribution facilities installed closest to the ratepayer (e.g., service drops, transformers, secondary distribution). The facilities investments are limited to those allowed pursuant to NV Energy's line extension rules ("Rule 9"). As the density of NEM systems increases, additional costs or savings may be identified, but no differences have been identified to date. (Ex. 2A at 30, 73-77, 110; Ex. 5A at 29, 72-76, 102.)

9. NV Energy states that customer costs are comprised of the revenue requirement associated with meter investment, and related meter expenses, customer accounting expenses, and customer service expenses. The meter investment was developed by class, and a generation meter was also developed for each NEM ratepayer class. While NEM and full-requirements ratepayers use identical billing meters, the NEM ratepayers' meters need to be programmed to measure bi-directional flow. The skillset requirements for replacing a standard-billing meter with the NEM-modified version necessitate that journeyman electricians or meter technicians perform such installations. The NEM ratepayer meter costs exceed those for the residential full-requirements ratepayer. (Ex. 2A at 68-71, 111; Ex. 5A at 64-66, 103.)

10. NV Energy states that the customer accounting and service costs are allocated to each class through the use of a CWFS, with the results applied to the historical costs used in the last MCSS. NV Energy states that there are two causes for the increase in NEM ratepayer customer costs: fully dedicated employees and the Renewable Energy Department. NPC has three customer service representatives plus one supervisor's allocated time, and SPPC has 1.5 customer service representatives to handle phone calls and manually review NEM ratepayers' bills. The department heads anticipate the cost per NEM ratepayer not to change, but there will be an increase overall in costs due to the increase in the number of NEM ratepayers. 94 percent of the Renewable Energy Department internal labor costs are allocated to NEM ratepayer classes. The Renewable Energy Department processes the NEM applications. As the program transitions from an incentive program to serving the NEM ratepayer classes, the internal labor costs will still be incurred. The MCSS determined that the NEM ratepayer classes have greater customer accounting and service expenses. (Ex. 2A at 29, 64-66, 69-73, 75; Ex. 5A at 28, 62-64, 68-72; Ex. 17A; Ex. 18A.)

11. NV Energy states that the marginal distribution demand related costs (non-revenue distribution feeders, substations, and high voltage distribution) are allocated between ratepayer classes based upon the class load shapes (e.g., contribution to the hourly load) and the hourly normalized probability of peak cost responsibility factor. [11] The NEM ratepayer's load shape for each fifteen-minute interval is the greater of the excess generation returned to the utility's system or the total load. The total load is the sum of the deliveries to the NEM ratepayer by the utility and the NEM ratepayer generation consumed by the NEM ratepayer during the fifteen-minute interval. The total load represents the maximum potential burden on the

[11] Probability of peak is based upon those hours during which there is a 90-percent probability that the system peak will occur. (Ex. 2A at 40-41; Ex. 5A at 40-41.)

distribution system if the NEM ratepayer were to lose their own generation. The excess generation above the NEM ratepayer's total load represents additional use of the distribution system by the NEM ratepayer to facilitate sending energy to the utility. The distribution system is designed to meet the ratepayer's estimated peak load demand, which is total load. No quantifiable primary distribution costs reductions have been identified for NEM customers. The excess generation component accounts for 0.1 percent of the NEM increase in marginal distribution costs, attributable to the excess energy occurring at times of relatively low distribution demand cost (primarily winter season). (Ex. 2A at 23, 40-41, 75, 78; 5A at 23, 37-40, 72.)

12. NV Energy states that until further studies are performed, no basis exists for altering the distribution planning at this time. Additional costs may be incurred in the future, depending on the level of NEM system penetration and additional clustering of NEM systems. NV Energy is conducting studies on the matter. (Ex. 2A at 77-79; Ex. 5A at 75-76.)

13. NV Energy states that the marginal transmission system demand costs were calculated consistent with calculations for all other ratepayer classes. As with distribution demand cost, the class transmission marginal cost allocation is calculated using the probability of peak and the class load shape. Consistent with the distribution demand, NEM generation is assumed to be contained within the distribution system; therefore, the NEM ratepayer class total load shape is used in the transmission cost allocation. Further, recognizing some load diversity does exist, the total hourly load was reduced by the ratio of the NEM class non-coincident peak to the total load non-coincident peak.[12] This reduction results in a transmission cost that is roughly eleven percent lower than that which would result if the total load shape were used, and

[12] The reduction was accomplished by comparing, on an hourly basis, the maximum delivered kilowatts ("kW") to the total load kW in the load shape. (Ex. 2A at 42; Ex. 5A at 42.)

it appropriately reflects the diversity of the NEM system self-generation and its impact on the loads of all ratepayers within the class. (Ex. 2A at 42-43; Ex. 5A at 42-43).

14. NV Energy states that it has not experienced any documented beneficial effects of NEM systems on the transmission system. NV Energy also states that it has not seen dramatic shifts in operational complexity or costs caused by NEM systems, but it notes that significant penetration relative to load during any time of the year could cause dramatic shifts in reactive power switching, generation dispatch, and unit ramping requirements. (Ex. 2A at 79, 81-82; Ex. 5A at 76, 78-79.)

15. NV Energy states that marginal generation demand costs were calculated in the same manner as those calculated for other ratepayer classes.[13] The NEM ratepayer class' delivered load shapes were used. The delivered load shapes recognize load diversity and NV Energy's inability to quantify the standby reservation and load-following costs. However, because system peaks are later in the day when rooftop solar production is in decline, the NEM ratepayer delivered load shape still results in significant capacity costs being allocated to these NEM ratepayer classes. (Ex. 2A at 24-25, 37, 39; Ex. 5A at 24-25, 37, 39.)

16. NV Energy states that the marginal energy costs were calculated in the same manner as they are calculated for other ratepayer classes. The NEM ratepayer class delivered load shapes were used. Marginal energy costs were developed consistent with the approved methodology used in NV Energy's last general rate case. The marginal energy costs were calculated hourly using the utilities' preferred integrated resource plan PROMOD for the

[13] Marginal generation costs allocated to each ratepayer class were determined by using the hourly loss of load probability calculated using PROMOD for the period of time before the next significant generation capacity addition. In the MCSS, with the next significant capacity addition forecasted to occur in 2020, the loss of load probability period was 2016-2019. (Ex. 2A at 38; Ex. 5A at 38.).

anticipated three-year rate effective period (2016-2018). The hourly data were averaged. The marginal energy costs were adjusted for line losses to the secondary distribution voltage level for each NEM ratepayer class. The adjusted hourly rate was multiplied by the NEM ratepayer class's delivered load shape. The resulting hourly amounts were aggregated by TOU period. (Ex. 2A at 25, 35-36, 61; Ex. 5A at 25, 35-36, 60.)

17. NV Energy states that the NEM ratepayer class load shapes were developed using all active NEM ratepayers as of March 31, 2015, for the entire study period of June 2014 through May 2015. Actual generation data was used when available. Missing hourly generation data was estimated using the average of those ratepayers that have at least 95 percent of the necessary fifteen-minute generation data. The compiled data was then compared to the National Renewable Energy Laboratory's averages for reasonableness. (Ex. 2A at 52-54; Ex. 5A at 50-52.).

18. NV Energy states that the E3 Study[14] is a cost/benefit study. A cost/benefit study does not estimate marginal costs or prices of any kind. Rather, it focuses on whether a specific investment, policy, or program is desirable or not. (Ex. 29A at 14-15; Ex. 30A at 14-15.)

19. NV Energy limited any ratepayer class revenue requirement change to that driven by the MCSS. The proposed rate revenue requirement represents the embedded revenue requirement allocated to each customer class using the MCSS developed class marginal revenue requirement through Statement O. Both the proposed and present rate revenue requirements were developed using the total general and base tariff energy rates effective July 1, 2015. (Ex. 2A at 46-47; Ex. 5A at 46-47.)

20. NV Energy states that the introduction of NEM systems coupled with the legacy

[14] The E3 Study was completed in Docket No. 13-07010, an investigation to examine the costs and benefits of net metering in Nevada pursuant to Assembly Bill 428 of the 77th Legislature (2013).

two-part rate structure has resulted in the shifting of costs and revenues. The utilities receive less revenue from ratepayers who continue to pay two-part rates after these ratepayers install NEM systems; however, the fixed and demand costs incurred by the utilities to serve the NEM ratepayers largely remain the same. Responsibility for these costs then shifts to non-NEM ratepayers during the reallocation of costs resulting from lower billing determinants (due to reduced energy use by the NEM ratepayers) in the next general rate case. As a result, NEM ratepayers are subsidized by non-NEM ratepayers when a simple two-part rate design that relies primarily on volumetric rates to recover demand and fixed costs continues to be used. (Ex. 29A at 10-13; Ex. 30A at 10-13.)

BCP Position

21. BCP states that it is concerned that the marginal distribution facilities costs (a portion of the ratepayer-related costs), developed by NV Energy in the most recent general rate cases and used in this proceeding, are unreasonable for all residential ratepayers. Rule 9 allowances have been skewed upward by an unrepresentative sample of new construction based on the small amounts of home building that occurred during the recession. The skewed study, in combination with higher Rule 9 allowances, resulted in higher marginal facilities costs. As a result, many residential ratepayers are in fact paying twice for their facilities—(1) through higher house prices arising from the lower Rule 9 allowances in place when their houses were built in the decade before the allowances were changed, and (2) through the marginal facilities costs based on current Rule 9 allowances. Therefore, BCP is concerned that all residential ratepayers, including residential NEM ratepayers, could be significantly overcharged. BCP was prepared to litigate this issue in NPC's last general rate case (Docket No. 14-05004) until that case settled with a zero rate change for everyone, which BCP believed was more advantageous than litigating

the case. BCP states that it believes that the proper forum for litigating the correct level of marginal facilities costs is in a general rate case. Piecemeal solar rates should not be developed based on marginal costs that have not been adequately vetted and which contain serious conceptual flaws. (Ex. 62A at 4-6.)

22. BCP states that the customer accounting effort studies prepared by NV Energy over the past two decades have always resulted in fairly accurate estimates but may not be totally accurate for small ratepayer classes. NEM ratepayers are a very small class for both utilities. In the past, BCP found anomalies in the overall marginal ratepayer accounting costs. Further, the supervisors and managers who fill out the forms used for the studies know that NV Energy is concerned about NEM, so choosing a higher number rather than a lower number within a range might not be surprising. Finally, some of the costs associated with NEM systems are likely to be one-time costs of connecting new NEM ratepayers, not ongoing costs for maintenance. Perhaps a one-time fee should be considered to collect some of those costs; however, such a fee cannot be estimated from the record before the Commission and should be an issue in a general rate case. (Ex. 62A at 6-7.)

23. BCP states that it is concerned that the load analysis conducted by NV Energy is overloading NEM ratepayers with transmission and distribution costs. Using the higher of total ratepayer loads or energy delivered to the utility in each hour to establish the distribution load pattern is not reasonable. Unless whole neighborhoods are solar, the feedback into the distribution system will be absorbed in a localized area and will not affect most of the distribution system, other than to reduce line loadings and losses. If a NEM ratepayer feeds power to its close neighbors for a few hours, the rest of the distribution system is largely unaffected. The same issue applies to transmission demands. While NV Energy points to the

construction of transmission to serve bulk power needs of various sorts, many of these lines are not load-related transmission but are in fact interties that are historically excluded from MCSS because they are theoretically considered to be incorporated in the marginal generation costs. NEM ratepayers who do not use as much peak energy as other ratepayers should not pay more for bulk power just because there is a generator behind the meter. (Ex. 62A at 7-9.)

Bombard Position

24. Bombard states that the Commission should not adopt NEM ratepayer classes that penalize ratepayers for contributing to Nevada's sustainable energy future. Any concern about cost-shifting between NEM ratepayers and non-NEM ratepayers can be handled adequately through a TOU rate. (Ex. 59A at 3).

25. Bombard states that TOU rates are designed to encourage ratepayers to reduce demand when energy prices are higher and to reward ratepayers by lowering energy prices to the ratepayer when the utility experiences lower energy costs. Accordingly, the utility value, and inherently the non-NEM ratepayer value, is included in the TOU rate. Further, TOU rates can and will be adjusted based upon economic principles of supply and demand through a general rate case adjudicated before the Commission, providing both the utility and ratepayers protection. If high penetration of NEM systems is experienced, then the Commission will have the opportunity to adjust the TOU rate in a general rate case. (Ex. 59A at 3.)

26. Bombard states that the E3 Study concluded that NEM policies do not result in NEM ratepayer free-riding and unreasonable cost-shifting; further, NEM ratepayers create an estimated total net present value to the non-NEM ratepayer of $36 million during the systems' lifetimes. NV Energy's attempts to demonstrate that NEM creates a burden on the system while providing little or no benefit does not make common or logical sense. (Ex. 59A at 4-5.)

SEIA Position

27. SEIA states that NEM is currently available in 43 states. There are currently 13 states where legislative efforts are under way, and 31 states where regulatory efforts are under way, to revise NEM policies. (Ex. 45A at 3.)

28. SEIA states that NEM has many economic and environmental benefits. These benefits include allowing NEM ratepayers to reduce their electricity bills and increase predictability over their electricity costs by hedging a portion of all of their electricity usage. NEM also increases the amount of clean energy consumed by the public and capitalizes on the most efficient method of producing electricity with no line loss—consuming electricity at the point of generation. NEM empowers ratepayers by offering them a choice and the ability to limit the amount of electricity they take from traditional investor-owned utilities. NEM also opens the door to innovation. That innovation triggers large capital investments in the advanced battery and smart grid sectors. (Ex. 45A at 4-5.)

SNHBA Position

29. SNHBA states the results of the MCSS are presented largely without limitation or qualification even though it appears to be a very preliminary work in progress. There is no quantification of the errors or range of variation in the input data used to conduct the MCSS or an estimate of the corresponding errors or expected variations in the calculated results from the MCSS. As a result, the MCSS do not meet the minimum requirements for transparency required to adequately evaluate the public policy recommendations contained in the filing. The analysis method is largely academic in nature and is based on idealized economic assumptions that do not actually apply to real residential homeowners. The MCSS are not grounded in real world policymaking or sufficient data. NV Energy's exclusive reliance on this analysis fails to account

for much of the value that rooftop solar is widely acknowledged to provide to the grid and NV Energy's ratepayers. (Ex. 41A at 17-18.)

30. SNHBA states that the MCSS are based on a large number of unsubstantiated cost assumptions. Further, many of the NEM ratepayer costs cited by NV Energy are a direct result of NV Energy's business decisions and are not caused by the NEM ratepayer. For example, the NV Energy's decision to apply demand charges to NEM ratepayers dramatically increases metering costs for NEM ratepayers compared to flat rate non-NEM ratepayers with demand charges—NV Energy will have to add the capability to evaluate a long stream of time series demand data for each NEM ratepayer in order to apply a demand charge to NEM ratepayers. Further, NV Energy's decision to require NEM ratepayers to have a generation meter dramatically increases metering costs for NEM ratepayers compared to non-NEM ratepayers. The primary purpose for the generation meter is to enable carbon offset benefits based on generation from the NEM systems. Yet, NV Energy ignores the value of carbon offsets. NV Energy attempts to justify its failure to account for the NEM benefits in its analysis by claiming that they are difficult to document due to the low penetration (less than one percent of total ratepayers) and broad geographical distribution of NEM systems. NV Energy's decision not to include NEM benefits in the MCSS is not supportable. There have been many previous studies of net NEM value that could have been used in NV Energy's analysis. (Ex. 41A at 8-9.)

31. SNHBA states that it is the reasonableness of NEM's financial implications that are being examined in this proceeding. NV Energy's analysis is rendered questionable by the E3 Study that concluded NEM policies do not result in solar free-riding and unreasonable cost-shifting. Instead, according to the E3 Study, there is a total net present value to non-participating ratepayers of $36 million during the NEM systems' lifetimes. (Ex. 41A at 14-16.)

Staff Position

32. Staff recommends that the Commission reject NV Energy's MCSS and Statement O and not use them to develop specific rates for the proposed NEM ratepayer classes. While Staff believes that NV Energy performed the MCSS consistent with SB 374, NV Energy's proposals do not appropriately and consistently use the methods of rate design for ratepayers that NV Energy has used in the past. (Ex. 82A at 1-2.)

33. Staff states that the most appropriate venue in which costs should be allocated and rates established for all ratepayer classes is a general rate case. In a general rate case, all parties and their respective experts can thoroughly review and analyze the data and provide their recommendations so that the Commission has sound and robust evidence for setting just and reasonable rates for all ratepayers. NV Energy should have utilized the allocations previously approved by the Commission in the most recently completed general rate cases, while using different billing determinants to generate a rate, thus keeping NV Energy revenue neutral. (Ex. 82A at 3-4, 9.)

34. Staff states that it is not appropriate to shift revenue from the NEM ratepayer classes to other ratepayer classes between general rate cases. Part of the change in revenue requirement is due to updating the inputs; however, the revenue requirement for several ratepayer classes has changed not only from updating the inputs but also from creating new NEM ratepayer classes. The rates to recover that adjusted revenue requirement should also reflect these changes. (Ex. 82A at 4.)

35. Staff states that the total load for NEM ratepayers was derived by summing the amount of delivered load plus the NEM ratepayers' generation output less the amount of energy produced by the NEM ratepayers' excess generation output received by NV Energy. In Staff's

view, this is an appropriate mathematical representation of a NEM ratepayer's load. If the NEM ratepayer's generation is off-line for any reason, NV Energy will then have to serve the load. Further, the load profile data was very robust with NV Energy using sample sizes anywhere from thirteen percent to thirty-six percent, which is a much higher percentage of ratepayers to represent the loads than what is normally used in a general rate case where NV Energy uses a sample size of less than one percent. However, the load profiles only show that NEM ratepayers are high usage ratepayers, not that additional costs are incurred to serve NEM ratepayers. (Ex. 82A at 4-6.)

36. Staff states that one load shape causes concern because NV Energy references an additional burden on the distribution system when excess generation from the NEM system is placed onto the distribution system. Staff states that it believes that the distribution system is not being burdened by the NEM systems and that it is merely in standby mode, although Staff recognizes that this could be a cost in the future. As the locational penetration of NEM systems increases, their production could exceed the capability of the distribution system. The impacts of increased locational penetration is something that would need to be analyzed as part of rate setting for the NEM ratepayer classes in a general rate case. However, at this point in time, increased locational penetration does not appear to be an issue. NV Energy should research and account for these costs and include that research when completed to assist in determining whether rates need to be further modified for NEM ratepayer classes in the next general rate case. (Ex. 82A at 7-8.)

37. Staff states that there are no specific benefits provided by NEM ratepayers to NV Energy in the short run. Staff asked Bombard, SEIA, TASC, and Vote Solar for support through specific examples of short run benefits, and none could provide this information. Benefits, if

any, come in the future. (Ex. 82A at 8-9.)

38. Staff states that NV Energy's use of estimated peak demand in the planning and designing of transmission and distribution systems is reasonable at this time. The forecasted NEM systems' output reduces NV Energy's overall peak demand and retail energy sales contained in the load forecasts. However, by 2017, NPC is forecasting the peak demand to occur in the early evening hours; therefore, NEM systems will have little to no impact on NV Energy's actual peak demand. Further, in order to serve the expected peak demand, NV Energy does not currently design its distribution systems to account for any NEM system output. It is unreasonable for NV Energy to design and install smaller-sized capacity distribution facilities that would not meet the expected peak demand due to the installation of NEM systems for two reasons. First, sizing capacity distribution facilities on the maximum peak demand is most appropriate to ensure reliable service to all ratepayers, including NEM ratepayers. NV Energy is generally obligated to serve all ratepayers in its service territories. If NEM systems experience a reduction in output or cease to operate entirely, NV Energy would be expected to reliably supply the NEM ratepayers' demand and energy needs. Second, the average service lives of NV Energy's distribution facilities (38-70 years) and NEM systems (20-25 years) do not align. In order to even consider downsizing distribution facilities to account for the installation of NEM systems, NV Energy would have to assume that the NEM systems would always be replaced once the original NEM systems reach their end-of-life. There is no data to support such an assumption, especially given ownership turnover, changing economic factors, etc. Therefore, at this point, it is impractical and unreasonable to design and install smaller sized capacity distribution facilities for NEM systems. (Ex. 83A at 1-5.)

39. Staff states that there are currently no short-term (less than three years) impacts or

benefits to NV Energy's transmission system due to the current NEM system penetration accounting for 1.5 percent and 1.84 percent of peak demand as of August 31, 2015, for NPC and SPPC, respectively. However, as the penetration of NEM systems continues to increase, NV Energy's transmission systems could experience short, steep ramping of generation (increases and decreases in generator output), decreased frequency response, and/or voltage instability as a result of the "duck curve". The "duck curve" represents the net load of a utility's electrical system with high solar photovoltaic ("PV") penetration and shows the dynamics associated with integrating solar PV. Similarly, there are currently no short-term impacts or benefits to NV Energy's distribution system. However, as the clustering and/or penetration of NEM systems increases on NV Energy's distribution system, voltage, frequency, and/or power factor stability issues may arise and require additional upgrades and/or mitigation procedures. NV Energy expects to fully implement modeling software by the end of 2015 and start load-flow studies of its distribution system based upon NEM system installations in early 2016. (Ex. 33A at 6-8.)

40. Staff states that the long-term (greater than three years) impacts and/or benefits NV Energy's transmission and distribution systems will experience due to NEM system penetration are currently unknown. As penetration increases, NV Energy will likely experience increased costs associated with mitigating the "duck curve" and the resulting effects on the distribution system. However, NEM systems may also provide benefits to ratepayers if the NEM systems delay or mitigate the need for any transmission system upgrades or capacity additions or reduce losses on the distribution system. Technological advances, such as cost-effective energy storage, may further mitigate the intermittency associated with NEM systems and may provide benefits to ratepayers. Staff states that until potential long-term benefits from NEM systems are more concrete, Staff does not believe it is reasonable to modify NV Energy's current use of the

estimated maximum peak demand in the planning and design of transmission or distribution systems. (Ex. 83A at 8.)

41. Staff states that the MCSS are not cost/benefit analyses. The MCSS look at what costs are incurred by NV Energy to serve ratepayers and how to allocate those costs to different classes of ratepayers. If benefits of NEM include decreased costs to different ratepayer classes, those benefits will eventually be reflected in the MCSS and the associated rates determined from the MCSS for that ratepayer class as well as other ratepayer classes. (Ex. 82A at 9.)

42. Staff states that the E3 Study should not be relied upon in the Commission's analysis. In a severe contrast to the MCSS, the E3 Study is a cost/benefit analysis, which utilizes different tests to assess the overall cost or benefit of NEM systems when viewed through different measurements. For the base case scenario, the E3 Study showed that non-NEM ratepayers receive a benefit from NEM ratepayers through the Ratepayer Impact Measure ("RIM") test. However, included in the E3 Study are alternative analyses of key drivers, including distribution avoided costs, retail rate design, retail rate escalation, demand charge reduction, and utility-scale solar PV power purchase agreement ("PPA") pricing—these inputs shape the authenticity of the E3 Study in that they reflect the validity of the E3 Study. The Commission should be aware that the E3 Study performed a sensitivity analysis for the utility-scale solar PV PPA pricing (from $100 per megawatt-hour ("MWh") in the base analysis to $80 per MWh in the sensitivity analysis). Using the $80 per MWh PPA pricing, the RIM test results indicate an estimated cumulative cost to non-NEM ratepayers through 2016 of $222 million. (Ex. 82A at 13-14.)

43. Staff states that NEM ratepayers do not impose any significant additional costs on NV Energy or other ratepayer classes at this time. Instead, rate design and recovery are at issue

here. NV Energy loses revenue from NEM ratepayers that was being recovered through rates when the NEM ratepayers did not have the NEM systems. Recovery of those revenues eventually shifts to other non-NEM ratepayers. Installation of NEM systems reduces NV Energy's sales, which correspondingly reduces billing determinants so that in subsequent general rate cases, the reduced billing determinants will likely lead to a shift of this lost revenue to other non-NEM ratepayers. (Ex. 64A at 12; Ex. 82A at 7.)

44. Staff recommends that the Commission find that it is in the public interest to establish new NEM ratepayer classes in this proceeding. New ratepayer classes are usually created as part of a general rate case, but the Commission may establish new ratepayer classes outside of a general rate case. There are generally three ways to differentiate ratepayers into classes: by cost differentiation, by usage differentiation, or by a combination of the two approaches. While there does not appear to be a significant difference at this time in the costs that NEM ratepayers cause compared to other non-NEM ratepayers, there is a significant difference between the usage profiles, and thus the cost recovery between those two types of ratepayers. Usage differentiations are used both to establish potential cost differentials as well as to ensure that the total cost recovery and allocations equal the authorized revenue requirement. After careful review of the load data and sales data (billing determinants) received in response to Staff data requests, it is clear that the load shape for NEM ratepayers is quite different from non-NEM ratepayers. When the revenue requirement for the residential and small commercial ratepayer classes is allocated, NEM ratepayers will avoid paying some of those costs if they are collected in the variable kilowatt-hour ("kWh") rate, and non-NEM ratepayers who are not offsetting their usage with self-generation will pay those avoided costs instead if NEM ratepayers are not in a separate rate class. It is not appropriate to require utilities to treat

ratepayers who have chosen to take service differently, and consequently who have different load profiles, in the same manner as those ratepayers who may not have such a choice. (Ex. 64A at 1-9.)

45. Staff states that the fact that NEM ratepayers' usage characteristics are different from non-NEM ratepayers is a sufficient basis for establishing separate NEM ratepayer classes. Additionally, establishing separate NEM ratepayer classes will diminish concerns regarding public policy and ratepayer perception and, to some extent, it will acknowledge the differences in the market structures of utilities and solar leasing companies. Finally, establishing new NEM ratepayer classes is in the public interest because it allows for more efficient tracking of NEM ratepayers' costs and billing determinants for use in future general rate cases or other ratemaking proceedings. (Ex. 64A at 10.)

TASC Position

46. TASC recommends that NV Energy continue to provide NEM at existing retail rates for residential and small commercial ratepayers. Doing so will not shift costs to non-NEM ratepayers because the marginal cost of service for NEM ratepayers is lower than that for non-NEM ratepayers after TASC's revisions to the MCSS inputs. (Ex. 68A at 49.)

47. TASC states that installation of a NEM system does not typically move a NEM ratepayer outside of the range of expected usage by other ratepayers in the same rate class. Even though loads for NEM ratepayers are reduced by NEM systems, NV Energy's delivered loads are still significant, with average bills estimated at $970 per year for NEM ratepayers of NPC and $870 per year for NEM ratepayers of SPPC. In fact, for the vast majority (85 percent to 95 percent) of NEM ratepayers, their delivered load remains well within the distribution of loads for the entire class. Becoming a NEM ratepayer does not typically move the NEM ratepayer outside

of the range of expected usage by non-NEM ratepayers in the same rate class. Thus, NV Energy's claim that NEM ratepayers' usage is somehow unique is baseless. There is no justification to establish new classes for NEM ratepayers or impose a three-part tariff as proposed by NV Energy. (Ex. 68A at 6-7; 9-16.)

48. TASC states that the cost differences between NEM and non-NEM ratepayers on which NV Energy's tariff proposals are based are limited to marginal ratepayer costs and marginal distribution demand costs. However, TASC disputes whether there are truly any differences with regard to either of these marginal costs. With respect to marginal ratepayer costs, NV Energy alleges that cost differences between NEM and non-NEM ratepayers exist with respect to revenue meter fees, a newly proposed generation meter fee, and ratepayer service costs. TASC has determined that the cost differences between NEM and non-NEM ratepayers for the revenue meter are related to programming and upfront activities related to interconnecting the new NEM ratepayer that are more appropriately recovered through an interconnection fee. TASC has also determined that there is no need for NV Energy to require new NEM ratepayers to install a generation meter. Finally, the costs associated with NV Energy customer service and billing personnel are overstated and largely cover expenses associated with initial adoption of a NEM system, which are more appropriately assessed to each new NEM ratepayer in an upfront application fee. Using this more appropriate assignment of costs, NEM and non-NEM ratepayers have very similar marginal costs. This fee and the underlying costs could be reviewed in more detail and with more experience in NV Energy's next general rate cases and adjusted as appropriate. (Ex. 68A at 7, 17-23, 35-48; Ex. 76A at 29-30.)

49. TASC recommends the use of metered loads for NEM ratepayers (i.e. what the ratepayer receives from NV Energy) for determining marginal distribution demand cost for NEM

ratepayers. TASC agrees that other than service transformers the secondary distribution systems are sized to supply maximum current. TASC asserts that the service transformer is able to handle short periods of overload without failure. TASC disagrees with NV Energy's assertion that it must design its other parts of the distribution system (e.g., service transformers, substations) to supply the peak load of NEM ratepayers under the condition of zero NEM generation rather than the delivered load served by NV Energy. Zero NEM system generation is extremely unlikely, and these other parts of the distribution system are not planned for this scenario. In fact, the peak load capacity has already been exceeded on parts of the distribution system, with no resulting outages over the past five years. Peak load is not a firm limit in distribution planning. Load diversity heavily influences equipment selection. Load diversity is the collection of customers being served, and not all types of customers peak at the same time. With increasing NEM system generation, NV Energy should see reductions in marginal cost on the distribution system as investments in other capacity resources are deferred. NV Energy's Applications list some possible technical concerns with NEM system generation, but good solutions exist (including the use of new smart inverter functions and the adoption of new software tools (i.e. quasi-static time series modeling) for all of the technical concerns NV Energy raises. It would take many simultaneous NEM system failures to significantly affect distribution system loading, and NV Energy has not presented those probability calculations. (Ex. 79A at 2-12.)

50. TASC recommends rejecting NV Energy's load shapes for marginal transmission demand and distribution demand costs. Geographic diversity of the rooftop solar systems mitigates the output fluctuations and their transmission system impacts. Even with non-coincident peaks in system load and fluctuations in total rooftop solar output, there is still a

reduction in the system net load. That reduction should be reflected in the load shape used for transmission marginal cost. Further, the residential NEM load shapes were not handled consistently, and the resulting impact increases the residential NEM ratepayer's average annual load for marginal distribution costs. These load shapes need to be consistent with the load shapes used by NV Energy for generation energy and capacity costs of service to reflect the costs actually imposed on the distribution system by NEM ratepayers. By correcting NV Energy's improper load shape assumptions, NV Energy's marginal costs of service for transmission demand and distribution demand for NEM ratepayers are much lower than those estimated by NV Energy, and they are also lower than the costs for non-NEM ratepayers. (Ex. 49A at 14-17; Ex. 68A at 7-8, 23-35; Ex. 79A at 4-5, 10-11.)

51. TASC disagrees with NV Energy's view of marginal distribution demand and banking costs. First, the distribution demand costs should reflect a true burden on the distribution system. The total load and the reverse flow offset each other; they do not add up as NV Energy proposes. Second, a banking cost on top of this demand cost would imply an energy storage capability that NV Energy is not actually providing. This banking cost is only an accounting mechanism, not reflected in actual distribution or energy storage capacity. (Ex. 79A at 11.)

52. TASC states that NV Energy has not demonstrated that there will be any cost-shifting, and certainly not any unreasonable cost-shifting. Regardless, even if the cost to serve NEM ratepayers is found to be higher than the cost to serve non-NEM ratepayers, the difference would not necessarily represent an unreasonable cost-shifting. In order to determine whether any amount of cost shifting is unreasonable, it is first necessary to estimate (1) the magnitude of any cost-shifting and (2) the magnitude of the electricity system benefits of the NEM resource.

These two critical pieces of information will indicate whether any cost-shifting, to the extent it does occur, is unreasonable. (Ex. 49A at 10-12.)

53. TASC states that the MCSS do not fully capture the long-term benefits of NEM. These benefits will accrue to NV Energy ratepayers over time with the addition of new, long-term renewable resources to NV Energy's system. Future benefits will also reduce NV Energy's costs to comply with the Renewable Portfolio Standard ("RPS") and Clean Power Plan requirements as well as reduce the future market prices of the utility's wholesale purchases of power. Electric system benefits include enhanced reliability and resiliency. Societal benefits include the avoidance of harmful impacts of carbon emissions. Local economic benefits include a growing NEM system industry. The Commission should consider the fact that the quantitative results of the MCSS are not likely to account for all the benefits of NEM systems due to the inability of such studies to fully reflect the long-term costs and benefits to the utility system and Nevada as a whole. The presence of these additional long-term benefits should confirm for the Commission that there is no reason to change the structure of NEM. Even if there are cost shifts, these additional benefits should be weighed by the Commission in deciding whether such a cost shift is unreasonable given that SB 374 does not prohibit all cost shifts, just those that are unreasonable. (Ex. 49A at 17-20; Ex. 79A at 32-48.)

54. TASC states that it is important for the Commission to understand the long-term utility system benefits in order to inform the ratemaking and rate design decision. First, if NEM is recognized as being very cost-effective and offering significant long-term benefits to the utility system, then NEM policies and rates should be designed to promote such a beneficial resource. Second, if there are concerns about cost-shifting, or any indication that cost-shifting might exist, then the magnitude of the long-term utility system benefits can help inform the decision of

whether any expected cost-shifting is reasonable. The conventional method for evaluating the long-term impacts of an electricity resource on the utility system is to quantify any increase or decrease in the utility's revenue requirements as a result of the resource. There have been several studies in recent years conducted in Arizona, Colorado, Hawaii, Maine, Mississippi, Nevada, New Jersey and Pennsylvania, and North Carolina that have found NEM resources to be very cost-effective in terms of reducing ratepayer revenue requirements. The fact that NEM ratepayers bear more or all of the cost of generating the power is what makes NEM so extremely cost-effective from the perspective of the present worth of revenue requirement ("PWRR"). Any increase in rates to account for the fact that a utility's sales are lower than they otherwise would be is driven by the reduced sales, not by any overall increase in revenue requirement that results from NEM. (Ex. 49A at 21-26.)

55. TASC states that the concept of a separate rate class for NEM ratepayers is inconsistent with ongoing changes in the electric industry. Ratepayers are being provided with increasing options to control their electricity consumption through energy efficiency, demand response, distributed generation, advanced meters, improved information, price signals, and more. Storage and plug-in electric vehicles are expected to result in significantly different consumption patterns and load shapes soon. If separate rate classes are established for NEM ratepayers, TASC questions whether the same should be done for ratepayers who take advantage of all these other available options. The potential number of permutations clearly make this path impractical and unsustainable. (Ex. 49A at 37-38.)

Vote Solar Position

56. Vote Solar states that NV Energy's proposal to separate NEM ratepayers into their own rate classes with different rates and rate structures is unsupported by the evidence

presented by NV Energy. (Ex. 44 at 4, 9-10.)

57. Vote Solar states that NEM ratepayers do not have unique load and cost characteristics as compared to non-NEM ratepayers and do not unreasonably shift costs to non-NEM ratepayers under current rates. All ratepayers, including NEM ratepayers, have a standby aspect to their electric service. Residential service loads are not constant, varying throughout the day and in some cases dramatically, so utilities must stand ready to meet the entire ratepayer load at all times. Similarly, because NEM systems are not uniformly intermittent, a group of NEM systems smooths the variability to a more predictable pattern, similar to a group of residential loads. Standing by ready to serve all ratepayers is the core business of the utility. (Ex. 44A at 4, 13-15.)

58. Vote Solar states that NV Energy has not provided evidentiary support demonstrating any distinct differences between the load factors of NEM ratepayers and non-NEM ratepayers in this proceeding. Even if NV Energy could, it would be a slippery slope of segregating ratepayers. Every subgroup of residential and small business ratepayers that has something in common, such as a particular size or load factor or behind-the-meter equipment could then be subject to segregation into a separate rate class. The issues NV Energy raises as being unique to NEM ratepayers are common to other groups of ratepayers. (Ex. 44A at 16-17.)

59. Vote Solar states that NV Energy's characterization of increasing distribution costs is unfounded and misleading. Such costs (in response to things such as reverse flow or voltage rise) are not happening or imminent. Penetration levels are too small to require additional costs on the part of NV Energy. If and when things such as reverse flow or voltage rise occurs, other utilities will almost certainly have developed strategies to manage such penetration levels. For the purposes of this proceeding, these threats of distribution cost

increases are unfounded and misleading and should be rejected. (Ex. 44A at 17-20.)

60. Vote Solar states that the MCSS do not take long enough views to capture the long-term (20-25 year) benefits of rooftop solar generation. The MCSS looks only at the marginal cost to serve NEM ratepayers and do not take into account the benefits of NEM system generation. Such a review was conducted in the E3 Study, showing that benefits exceed costs under current rates with the implication that current rates do not result in a shifting of costs. While some of the underlying figures and assumptions in the E3 Study have changed, the E3 Study results should stand until such time as the E3 Study is comprehensively updated. (Ex. 44A at 22-24.)

61. Vote Solar states that the MCSS submitted by NV Energy have several problems, including: flawed NEM ratepayer load shapes, which were used to allocate transmission and distribution costs; over-allocation of customer costs to the NEM ratepayer classes; and double-recovery of revenue related to the NEM ratepayers' excess generation. (Ex. 44A at 23.)

62. Vote Solar states that for transmission load shapes, NV Energy uses the total load shape scaled downward to reflect the difference between the non-coincident peaks of the total load shape and the delivered load shape to assign transmission costs; however, only the delivered load shape should be used to assign transmission related costs in the MCSS. First, NV Energy does nothing to manage the outflows from a NEM system. As a result, there are no transmission-related costs associated with those energy exports. Second, rooftop solar (spread out across the grid) will likely have even higher capacity values than large-scale solar PV systems to which NV Energy assigns a capacity value of 38 percent. As a result, rooftop solar has a capacity value that will help NV Energy avoid future investments in generation and transmission. (Ex. 44A at 25-27.)

63. Vote Solar states that for distribution load shapes, NV Energy uses the greater of ratepayer load delivered by NV Energy or excess generation (energy exports); however, energy exports from NEM ratepayers' systems reduce the loading on the distribution circuit, distribution system, and transmission system and reduce generation needed to serve that distribution circuit. There is no added cost at current or anticipated penetration levels. As a result, the delivered load shape should be used for the assignment of distribution-related costs in the MCSS. (Ex. 44A at 27-28.)

64. Vote Solar states that for customer costs, NV Energy revised the CWFS approved in the last general rate cases to develop marginal customer accounting and customer service costs. The revision resulted in an over allocation to the proposed NEM ratepayer classes because it was conducted in such a way that would make it prone to inaccurate results. Department heads were tasked with a retroactive assignment of recorded costs to a subset of ratepayers where each department head was given significant liberty with which to assess his/her department. There was also insufficient vetting of department head responses. The ratio of costs per NEM ratepayer to costs per non-NEM ratepayer were surprising in a number of departments. As a result, the revised CWFS should be excluded from NV Energy's MCSS. Going forward, NV Energy should be instructed to record costs separately for NEM ratepayers as they are incurred and with detailed support rather than estimate the separation after the fact. (Ex. 44A at 29-38.)

65. Finally, Vote Solar states that NV Energy has essentially proposed to receive payment for energy exports from a NEM system from two different sources. The first payment comes from the ratepayer near the NEM system who actually receives that power and pays NV Energy for it. The second payment comes from NV Energy calculating a value for exports (banking) and charging the total amount to all ratepayer classes. This double-recovery is

improper and must be rejected. (Ex. 44A at 38-39.)

66. Vote Solar states that there are also underlying data problems with the MCSS that likely lead to skewed results. First, NV Energy used inconsistent load data (different twelve-month periods), which may lead to inaccurate results, especially given the significant year-over-year NEM ratepayer growth in each service territory. Second, NV Energy updated the production costs modeling in the MCSS with an analysis completed in May 2015. The production costs modeling underlying the general rate cases for NPC and SPPC were previously completed in April 2014 and June 2013, respectively. Because the underlying marginal cost data, the spread of the marginal costs across the hours of the year, and the NEM ratepayer load shape data are all based upon different timeframes, the results of the analysis are likely to be skewed in different directions. However, there is insufficient data in this proceeding to say by how much and in what direction. This is best handled in the next general rate case. As a result, Vote Solar urges the Commission to be especially cautious about establishing new and far-reaching policies based upon this data. (Ex. 44A at 39-43.)

67. Vote Solar states that when all of these flaws are corrected, the MCSS actually indicate that the costs to serve NEM ratepayers are less than the costs to serve non-NEM ratepayers. (Ex. 44A at 4, 44-46.)

68. Vote Solar recommends that the Commission direct NV Energy to perform new MCSS using consistent data and incorporating the other corrections included above in SPPC's and NPC's next general rate cases. Corrected MCSS will help NV Energy and the Commission determine whether a new rate for NEM2 ratepayers is beneficial and in the public interest. (Ex. 44A at 5-6).

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NV Energy Rebuttal Position

69. NV Energy maintains that the Commission should adopt separate rate classes for NEM ratepayers based on the MCSS. The MCSS were developed for these filings using methodologies and inputs that are wholly consistent with the models that have been reviewed and approved by the Commission in past general rate cases. The inputs and analysis that went into these filings were critiqued, discussed, and vetted though all areas of the organization. The amount of time, effort, analysis, and development rivaled that of preparing two general rate cases in a condensed timeframe, yet the amount of consideration that went into each and every input and modification from previously approved MCSS is quite possibly greater than any other utility has put into analyzing and developing rates for NEM ratepayers in the United States. Simply ignoring that analysis and using a blunt tool such as the full-requirements MCSS and rate design to propose admittedly arbitrary rates for NEM ratepayers, as Staff proposes, is wholly inappropriate and should not be considered a viable alternative to NV Energy's proposal. (Ex. 99A at 58-63.)

70. NV Energy states that BCP's characterization of NV Energy's MCSS is incorrect and misleading. It is also wholly inconsistent with the evidence presented by NV Energy in these proceedings and the position and arguments set forth by BCP in its Petition and corresponding comments in Docket Nos. 14-03026 and 14-06009. In those proceedings, BCP stated that NEM ratepayers have unique demand characteristics, and one of the consequences of these differences in demand characteristics is that NEM ratepayers have different costs of service than full requirement ratepayers. BCP's other arguments and concerns about NV Energy's MCSS have been presented and rejected by the Commission in previous dockets. BCP presents no new arguments or information in this proceeding. (Ex. 99A at 22-28.)

71. NV Energy states that it disagrees with BCP's claim that the output of NEM installations is relatively predictable and, therefore, the utility should focus on delivered load. A review of the data reveals that there are differences between the delivered load attributes of NEM ratepayers and non-NEM ratepayers. Further, data highlights that the delivered load shapes for NEM ratepayers and non-NEM ratepayers is different. The largest changes occur on cloudy days when NV Energy is standing by to meet the instantaneous electrical demand and energy needs of all NEM ratepayers. Differences show that non-NEM ratepayers have smoother transitions or less volatile delivered load than non-NEM ratepayers. There is a difference in demand requirements within an hour as well as across hours between NEM ratepayers and non-NEM ratepayers. (Ex. 89A at 9-11.)

72. NV Energy agrees with Staff that there is a significant difference between the load shape (usage profiles) of NEM and non-NEM ratepayers, thus supporting the establishment of new NEM ratepayer classes. The total load shape and delivered load shape of NEM ratepayers are distinct and vary from the load shapes of non-NEM ratepayers on an hourly basis. Differences in hourly load shapes thus reflect the differences in the costs incurred by NV Energy to provide the unique and specific energy services required by NEM ratepayers. NV Energy also conducted an Epps-Singleton equality of distribution test to further demonstrate that the total hourly loads of the two groups are statistically different. Hourly, not monthly (as TASC asserts) load shapes provide information regarding the cost of providing service to groups of ratepayers. Similarities in the ranges of monthly consumption may mask marked differences in the time-of-day consumption and, therefore, the facilities required to provide service to a class of ratepayers. TASC used truncated charts with numerous data errors to try and demonstrate that the residential ratepayer class as a whole and the residential NEM ratepayers within that class are very similar.

TASC confirmed in deposition that it did not perform any statistical analysis to determine whether there was a statistically significant difference between these NEM and non-NEM ratepayers. (Ex. 89A at 4-9; Ex. 90A at 1-2; Ex. 99A at 29-30.)

73. NV Energy disagrees with numerous assertions made by TASC concerning distribution system planning. It is normal distribution planning practice to size the distribution system based upon a ratepayer's full estimated peak load. This sizing reflects the true burden on the distribution system. The potential extent of cloud cover, especially in the Las Vegas Valley, could surely cause the output of many NEM systems to drop to near zero simultaneously. Also, the planned overloading of distribution equipment under normal operating conditions for what could be repeated instances on a continual annual basis is not within commonly accepted good utility practice—stress on the equipment due to overloading causes accelerated loss of life. NV Energy has not identified any currently planned distribution investments that can be eliminated or deferred due to NEM systems. Even though NEM systems may reduce distribution system loading to a certain degree during peak loading conditions, the distribution system must still be designed to accommodate the full load requirements of ratepayers. Until future studies indicate otherwise, NV Energy does not believe there is a basis for altering the distribution design criteria and planning methods for the distribution system based upon NEM systems. Finally, while there are technical solutions available to address the impacts of expected higher penetrations of NEM systems on the distribution system in the future, these solutions will come at a cost. (Ex. 84A at 3-15.)

74. NV Energy states that in order to accurately reflect the costs for NEM ratepayers, the load shapes that are necessary to develop the cost of service must (1) include the generation that the NEM ratepayer sends back on to the distribution system and (2) reflect the standby

nature of the service that NV Energy provides to these ratepayers to account for the facilities that are installed to meet the NEM ratepayers' energy requirements when their systems are not producing energy. It is appropriate to include the generation from NEM ratepayers that is sent back onto the grid as this is additional load on the distribution system. Significant amounts of generation are physically delivered by NEM ratepayers to the grid—approximately 42 percent and 49 percent of all NEM system generation for NPC and SPPC, respectively. No party to this proceeding produced any evidence that correlates the installation of NEM systems with a reduction in energy consumption. Further, rates for NV Energy's other partial-requirements standby ratepayers are based upon the total loads of the otherwise applicable schedules, which represent ratepayer loads in the absence of self-generation. As with the distribution system, the standby nature of NEM service means that NEM ratepayers physically affect the transmission system for loads that are required when their generation is not producing. Therefore, the costs of providing this standby component of service should be reflected in the development of transmission costs for NEM ratepayers. (Ex. 93A at 8-12; Ex. 99A at 38-45.)

75. NV Energy states that the CWFS takes a forward-looking approach to the allocation of expenses. NV Energy looked at historical expenses, logically evaluated those historical costs, and proposed adjustments where appropriate to reflect expected going-forward levels of expense, consistent with prior general rate case filings. NV Energy must continue to administer the Solar Energy Systems Incentive Program ("SolarGenerations program") for at least five more years to process the performance-based incentives, so the cost allocation is reasonable with respect to the effective period of the rates in question. The large disparity in customer service representatives serving NEM ratepayers versus non-NEM ratepayers highlighted by TASC and Vote Solar is inaccurate because the NEM customer service

representatives perform not only call center functions but billing department functions; the disparity drops by many multiples when the total number of customer service representatives is recognized. Further, when it comes to determining the most reasonable allocation of expense on a going forward basis, the department head has the experience and knowledge to determine the most applicable and reasonable allocation of expenses for the department under his or her direction. While Vote Solar requests that NV Energy record NEM costs separately, tracking specifically incurred costs, the cost of doing so (creation of tracking mechanisms, training of employees, and modification of systems) would increase the cost of providing NEM service. (Ex. 91A at 3-9; Ex. 99A at 81-84.)

76. NV Energy states that externalities, such as societal, economic, and environmental costs and benefits, should not be included in a MCSS. This approach conflates two separate and distinct regulatory processes: (1) the rate setting process, and (2) the resource planning process. Such externalities may be important in determining the choice of resources in an integrated resource plan, however, rates are based on marginal (internal utility) costs and do not reflect external benefits or costs for any class. The Commission does not attempt to assess and reflect the saturation of energy efficiency measures taken, demand response programs, charitable contributions, or other investments that ratepayers make—all ratepayers receive the direct benefits from their participation and investments in such things. External societal costs are not included in the cost recovery that NV Energy's rates provide, and no exception should be made for NEM ratepayers. The Commission should reject proposals to weigh speculative, unquantified future values of NEM to offset current, known costs.[15] When determining the rates

[15] For instance, NV Energy states that it disagrees with the assertion made by TASC regarding NEM system benefits for future RPS compliance. The value of Renewable Energy Credits ("REC") has plummeted over the last couple of years as states have brought additional resources on-line at increasing rates. Any impacts to the value of RECs in the future due to regional markets, an increased RPS, etc. is simply speculative at this time. Further, if there is a

that ratepayers pay for service, the appropriate method of allocating the embedded revenue requirement to ratepayer classes is on the actual costs to provide the service. (Ex. 99A at 45-50; 101A at 39.)

77. NV Energy agrees with Staff that the E3 Study shows that existing NEM1 service has a significant negative impact on NV Energy's rates. The RIM test quantifies the impact of NEM service on non-participating ratepayers. When the RIM test result is negative, rates increase and costs are shifted from NEM ratepayers to non-NEM ratepayers. According to the E3 Study, RPS compliance value constitutes a large portion of the estimated 2014-2015 benefits. In the absence of an RPS, NEM systems would be compared to thermal generations, and non-NEM ratepayers would experience a net cost of $0.06 per kWh generated. Another important conclusion of the E3 Study is that utility-scale solar PPA prices can drive the cost-effectiveness results. With a utility-scale solar PPA price of $80 per MWh, the RIM test shows a $220 million subsidy to NEM ratepayers. The result is exacerbated with the current utility-scale PPA prices below $50 per MWh. (Ex. 101A at 42-44).

78. NV Energy states that when NEM ratepayers reduce energy consumption with rooftop solar generation, the NEM ratepayers lower their bills at the full retail energy rate, which includes charges not only for fuel costs but also for fixed and demand costs that do not go down because the NEM ratepayers consumed less energy. Because NEM ratepayers are under-paying, the difference has to be collected from non-NEM ratepayers. The collection of the difference from non-NEM ratepayers is an inequity, which is being addressed and resolved by NV Energy's proposals. It is important to note that this issue of under-collection of revenue from NEM

need for RECs in the future, NV Energy's preference would be to source the RECs from larger, utility-scale projects. Such projects provide a more certain stream of future RECs as they have contractually defined delivery requirements with consequences for non-performance, and the administrative cost of obtaining, certifying, and verifying RECs is considerably lower with a single site and single meter. (Ex. 85A at 10-11.)

ratepayers and over-collecting of revenues from non-NEM ratepayers is an equity issue even if NEM and non-NEM ratepayers have identical marginal costs of service. NV Energy states that the rationale for its proposal is to reverse the inequity between NEM and non-NEM ratepayers, not between NEM ratepayers and the utility. (Ex. 87A at 7, 11.)

79. NV Energy states that only Staff seems to understand that by its nature, partial-requirements service ratepayers have lower billing determinants that, if applied to full requirements rates, will result in costs not being recovered from partial-requirements ratepayers. This, in turn, results in costs being shifted to other ratepayers, resulting in subsidies. In order to reduce or eliminate cost shift associated with partial-requirements ratepayers, rates have to be designed to recover certain capacity and fixed costs considering the lower billing determinants. Regardless of whether costs are specifically calculated for the group of partial-requirements ratepayers, enough revenue will not be generated to recover whatever costs were intended to be recovered from the particular rate if the rate design does not compensate for the differential in billing determinants. (Ex. 99A at 55-57.)

80. NV Energy states that, under NEM1, there is a significant shift in cost responsibility when a ratepayer installs a NEM system. This amount can be quantified using the existing base tariff energy charge ("BTER") and total energy production of the NEM system. On average, the resulting shift in cost responsibility is about $661 and $511 per NEM ratepayer annually for NPC and SPPC, respectively. The total subsidy (cost shift) from non-NEM ratepayers to the full 235 MW of NEM1 ratepayers will be $28 million annually. NEM ratepayers have chosen a different manner by which to meet their electric service needs. It is no longer appropriate to ask non-NEM ratepayers to pay more for their service as a result of the choices NEM ratepayers have made. (Ex. 99A at 16-17; Ex. 101A at 11-18.)

81. NV Energy states that the MCSS support the development of new NEM ratepayer classes due to the unique load and cost characteristics of these ratepayers that extend to every aspect of the service provided by NV Energy. NEM ratepayers have different billing determinants, different load shapes, different demand and energy relationships (load factors), different levels of variation across and within an hour, and different requirements on NV Energy, including standby service, additional customer service, accounting and metering needs, compared to full requirements ratepayers. The creation of separate classes for NEM ratepayers allows the Commission to establish fair and equitable cost-based rates that reflect the unique services provided to these partial-requirements ratepayers. Even if the cost to serve NEM ratepayers is lower than the cost to serve non-NEM ratepayers as TASC asserts, all of the other differences associated with NEM ratepayers still warrants the establishment of separate NEM ratepayer classes. (Ex. 87A at 7-8; Ex. 93A at 2-5; Ex. 99A at 30-38; Ex. 101A at 26-29.)

Commission Discussion and Findings

MCSS

82. Pursuant to Section 4.5(1) and (2) of SB 374, NV Energy was required to file a cost-of-service study in support of a tariff with the terms and conditions of service that includes the rates the utility must charge for providing electric service to NEM ratepayers (customer-generators). NV Energy conducted MCSS for NPC and SPPC.

83. The Commission uses MCSS to allocate the embedded revenue requirement to the various customer classes as the means of implementing accepted economic principles into the rate making process.[16] Marginal costing enhances economic efficiency by providing price signals as to the future cost structure facing the utility. The MCSS estimate the cost of the new

[16] NAC 704.660 requires the Commission to consider the utility's marginal costs in the determination of each ratepayer class's revenue requirement.

or next increment of utility investment (e.g., generation, transmission, and distribution). Rates are balanced in Nevada by using marginal cost pricing along with an historical test year and other rate-making considerations (e.g., understandability of rates).[17] As a result of this balancing, the MCSS guides the development of each ratepayer class's total revenue requirement and rate design. In these proceedings, the Commission views the statutorily-required MCSS as guides to aid the Commission in its evaluation of the NEM rates and tariffs.

84. NV Energy's MCSS for NPC and SPPC provides reasonable estimates for the marginal costs of providing service to NEM ratepayers and shall be used for purposes of allocating costs and establishing rates for NEM ratepayers in this proceeding. The MCSS were based on the latest versions used in each utility's last respective general rate case (SPPC's compliance filing in Docket No. 13-06002 and NPC's certification filing in Docket No. 14-05004). The MCSS included updated inputs to remove stale or outdated information and new inputs necessary to reflect the unique characteristics of the NEM ratepayer classes. While parties raised several issues pertaining to load shapes, transmission and distribution marginal costs, customer facilities costs, customer costs, etc., NV Energy adequately explained the reasons for the inputs in the MCSS. Of particular note, the other parties' proposals for load shapes afford no weight to the standby service that NV Energy provides to partial-requirements NEM ratepayers, which would effectively shift the cost burden to non-NEM ratepayers—such cost shifting is not reasonable or in the public interest.

85. Parties' proposals to weigh speculative, unquantified future benefits/values of NEM to offset current, known costs are rejected. These proposals conflate two separate and distinct regulatory processes: (1) the rate setting process, and (2) the resource planning process.

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[17] NAC 704.662(1)(c)(2).

When determining the rates that ratepayers pay for electric service, the revenue requirement is allocated to ratepayer classes based on the actual, measurable costs of providing service. Future benefits/values of NEM should be evaluated in the resource planning process. Rates are based on marginal (internal utility) costs and do not reflect external benefits or costs for any ratepayer class. External societal costs and benefits are not included in the cost recovery that NV Energy's rates provide for any class.[18] No exception should be made for NEM ratepayers.

86. It is also unreasonable to rely on the results of the E3 Study for purposes of cost allocation for NEM ratepayers. The E3 Study was conducted for purposes of informing legislative policy decisions regarding NEM and rooftop solar development in Nevada based on the costs and benefits to various groups.[19] Conversely, pursuant to the mandates in SB 374, the Commission is not to engage in the type of policy-making reserved for the Legislature, but rather to accurately allocate the costs required to serve NEM ratepayers.

87. Based on the foregoing, NV Energy's MCSS demonstrate that NEM ratepayers have unique service and cost characteristics. These differences result in the revenue requirement allocated to NEM ratepayers in the MCSS to exceed the revenue requirement currently collected from NEM ratepayers.

88. The current subsidy ranges from $9-114 each month for NPC's NEM ratepayers

[18] The Commission does not attempt to assess and reflect on the saturation of energy efficiency measures, demand response programs, charitable contributions, or other investments that ratepayers make. All ratepayers receive the direct benefits from their participation and investments in such things.

[19] The E3 Study (see Docket Nos. 13-07010 and 14-06009) was a snapshot in time for purposes of reviewing the costs and benefits of rooftop solar in Nevada. The $36 million figure highlighted by several parties was based on data current as of December 2013. That data is now two years old and did not include, among other things, the resource planning costs for compliance with SB 123 (2013). Further, numerous assumptions were made in the E3 Study, including the price of utility-scale solar at $100 per MWh. While the E3 Study contained a sensitivity analysis at $80 per MWh, turning the $36 million benefit to non-NEM ratepayers into a $222 million cost to non-NEM ratepayers (see Docket No. 13-07010, E3 Study filed 7/2/14, at 19-21, 128-130), the two most recent utility-scale contracts approved by the Commission (see Docket No. 15-07003, Order issued 9/10/15) have a levelized cost of energy below $50 per MWh. This new information demonstrates that the E3 Study is already outdated and irrelevant to the discussion of the costs and benefits of NEM in Nevada for purposes of marginal cost allocations in this proceeding.

and $39-$98 each month for SPPC's NEM ratepayers:

NPC	RS-NEM	RM-NEM	LRS-NEM	GS-NEM
MCS Allocated Revenues	$9,129,987	$70,376	$47,466	$220,061
Present Rate Revenues	5,787,670	45,201	46,590	128,266
Revenue Difference	$3,342,317	$25,175	$876	$91,795
Monthly Bills	64,416	900	96	804
Average Monthly Subsidy per NEM Customer	$51.89	$27.98	$9.13	$114.17

SPPC	D-1-NEM	GS-1-NEM
MCSS Allocated Revenues	$1,293,051	$494,043
Present Rate Revenues	788,084	321,360
Revenue Difference	$504,967	$172,683
Monthly Bills	12,876	1,764
Average Monthly Subsidy per NEM Customer	$39.22	$97.89

(Ex. 2A at 11, 21, 33-35, 96, 163-164, 177-187; Ex. 5A at 11, 21, 32, 35, 93, 162, 166-172, 174.) On average, the resulting shift in cost responsibility is approximately $623 and $471 for each single family residential NEM ratepayer[20] annually for NPC and SPPC, respectively. The magnitude of this cost shift is unreasonable.

Separate Ratepayer Classes

89. New ratepayer classes are usually created as part of a general rate case, but the Commission may establish new classes outside of a general rate case when appropriate. Pursuant to Section 2.3(2)(a) of SB 374, the Commission may establish one or more rate classes for NEM ratepayers in this proceeding. There are generally three ways to differentiate

[20] NPC's current RS and SPPC's current D-1 residential NEM ratepayers make up approximately 97 percent and 88 percent of the NEM ratepayers that are the subject of this proceeding.

ratepayers into classes: cost differentiation, usage differentiation, or a combination of the two.

90. Partial-requirements service, including electric service for NEM ratepayers, presents both a cost issue and a rate design issue (and revenue recovery issue) in this proceeding. The issue is the relationship between reduced consumption and the cost to provide service. When NEM ratepayers reduce energy consumption with solar generation, the NEM ratepayers lower their bills at the full retail energy rate, which includes charges not only for fuel costs but also for fixed and demand costs; these fixed and demand costs do not go down simply because the NEM ratepayers consume less energy. In other words, the reduction in the amount of electricity delivered to the NEM ratepayer after the installation of the NEM system does not result in a proportional decline to the cost of providing service. The price charged does not equate to the cost to provide service. As a result, NEM ratepayers are under-paying, and the difference has to be collected from non-NEM ratepayers (eventually via reallocation in the next general rate case) if NEM ratepayers are not in separate rate classes. By placing NEM ratepayers in a separate class, the Commission can design rates that effectively collect those costs through an alternative rate structure. Separate rate classes will address the inequity between NEM and non-NEM ratepayers that exists under the NEM1 framework. The subsidy to NEM ratepayers under NEM1 is not paid by the utility as some parties incorrectly suggest; rather, the subsidy flows from non-NEM ratepayers to NEM ratepayers, with the utility collecting the same amount regardless of how costs are allocated among the different ratepayers. Indeed, NV Energy's revenues will not increase as a result of the Commission requiring NEM ratepayers to pay their full share of costs.[21]

91. It is just and reasonable and in the public interest to establish separate rate classes

[21] See discussion on NV Energy's request to establish regulatory liability accounts in Section VII D below.

for *all* NEM ratepayers based on both the cost differentiation and load (usage) differentiation between NEM ratepayers and non-NEM ratepayers. Different services have different costs and thus require different rate classes. NEM ratepayers are partial-requirements service ratepayers. The Commission has historically established separate, optional rate schedules for ratepayers who self-select to become partial-requirements ratepayers.[22] Partial-requirements service ratepayers are ratepayers whose electric requirements are partially or totally provided by non-utility generation. There is a significant difference in the load (usage) profiles between partial-requirements NEM ratepayers and full-requirements ratepayers. NEM ratepayers can rapidly go from exporting unused electricity to importing needed electricity from the local grid. As a result, NV Energy provides a distinct service to partial-requirements ratepayers who choose to purchase some, but not all, of their energy needs from the utilities.

92. Besides the partial-requirements nature of NEM ratepayers' service, the load levels and hourly usage differences between NEM and non-NEM ratepayers are sufficient (alone) to justify separate ratepayer classes for NEM ratepayers. There is a significant difference between the load shapes (usage profiles) of NEM and non-NEM ratepayers, thus supporting the establishment of new NEM ratepayer classes. The total load and delivered load of the NEM ratepayer is distinct and varies from the shape of non-NEM ratepayers on an hourly basis. Differences in hourly load shapes thus reflect the differences in the costs incurred by NV Energy to provide the unique and specific energy services required by NEM ratepayers. NV Energy also

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[22] Historically, NV Energy has distinguished between full and partial-requirements ratepayers. However, in 1997, the Nevada Legislature adopted a pilot program for NEM ratepayers essentially eliminating this historical distinction. Subsequently, in 2015, the Nevada Legislature ended the pilot program by authorizing the Commission to again recognize that partial-requirements NEM ratepayers receive unique services from NV Energy and authorized the Commission to address those distinctions by adopting unique rate designs and corresponding prices to recover the costs for serving NEM ratepayers.

conducted an Epps-Singleton equality of distribution test to further demonstrate that the total hourly loads of the two groups are statistically different. Hourly, not monthly, load shapes provide information regarding the cost of providing service to groups of ratepayers. Similarities in the ranges of monthly consumption may mask marked differences in the time-of-day consumption and, therefore, the facilities required to provide service to a class of ratepayers.

93. The fact that NEM ratepayers' usage characteristics are different from non-NEM ratepayers is a sufficient basis for establishing new NEM ratepayer classes. However, establishing new NEM ratepayer classes is also in the public interest to allow more efficient tracking of NEM ratepayers' costs and billing determinants for use in future general rate cases or other ratemaking proceedings. Even if the total costs for NEM ratepayers were currently the same, which they are not, the types of costs are different because they reflect the different types of service provided by NV Energy. Separate ratepayer classes will help capture any change in those costs (higher or lower) in the future. For instance, the impacts (both costs and benefits) of expected higher penetration of NEM systems on the distribution system in the future will need to be addressed.[23] Future impacts on the distribution system are something that would need to be analyzed as part of rate setting for the NEM ratepayer classes in a general rate case. However, at this point in time, there do not appear to be any impacts on the distribution system. NV Energy shall study and account for the costs and benefits of higher penetration of NEM systems on the distribution systems and include the results when completed to assist in determining whether rates need to be further modified for NEM ratepayers in future general rate cases.

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[23] For example, as the locational penetration of NEM systems increases, their production could exceed the capability of the distribution systems.

V. RATE DESIGN

NV Energy Position

94. NV Energy recommends a three-part rate design for new NEM ratepayers. The rates are based on the MCSS. The three-part rates include a monthly service charge, a demand charge, and an energy charge. Two choices are being offered to NEM ratepayers, one of which does not have a time variation in the demand and energy charges, and one of which does have a time variation in these charges. (Ex. 29A at 3; Ex. 30A at 3.)

95. NV Energy states that the proposed rates are consistent with the five principles of rate design: (1) economic efficiency, (2) equity, (3) bill stability, (4) revenue stability, and (5) customer satisfaction.[24] These principles accord with the established notion of cost causation in rate design. Economic efficiency and equity relate directly to the notion of cost causation. Economic efficiency is achieved by having cost-reflective prices, while respecting the equity principle requires that the tariff's design not result in one ratepayer unintentionally subsidizing another ratepayer. Prices that are cost-reflective minimize unintentional subsidies. However, cost causation may need to be balanced against the other core principles such as customer satisfaction or bill stability. (Ex. 29A at 4-8; Ex. 30A at 4-8.)

96. NV Energy states that according to the notion of cost causation, rate structures should match the nature of the costs and have a fixed service charge, a demand charge, and an energy charge. The demand and energy charges might vary with the time of use of electricity and have different seasonal and/or peak/off-peak charges. Most commercial and industrial ratepayers across the country are served under cost-reflective, three-part rate structures. Historically, residential ratepayers have not been served under three-part rate structures;

[24] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen coalesced economists' thinking on theoretical rate design in Principles of Public Utility Rates, 2d ed. (Arlington, VA: Public Utility Reports, 1988).

however, this is changing rapidly due to several technological advances, including advanced metering infrastructure ("AMI") that have emerged in the last several years.[25] At least 19 utilities in 15 states are currently offering three-part rates to residential ratepayers. (Ex. 29A at 8-10, 17-26; Ex. 30A at 8-10, 17-26).

97. NV Energy states that, currently, residential NEM ratepayers continue to pay the same rates as their otherwise applicable tariff schedule. This schedule includes a monthly fixed charge (the basic service charge) and a variable (volumetric) charge. Ratepayers have a choice of a flat volumetric rate or a TOU volumetric rate.[26] Any excess kWh production from the NEM system is credited on the otherwise applicable tariff schedule. This credit goes into a "bank" account, which is used to pay for kWh consumption either in the current or future billing period. (Ex. 29A at 10-11; Ex. 30A at 10-11.)

98. NV Energy states that the MCSS are the proper pricing tools for cost-based rates. Prices send signals to ratepayers about what actions to take and to the utility about what investments to make. If these price signals are cost-reflective, then optimal decisions will be made that raise economic efficiency and enhance ratepayer well-being, making society better off. MCSS establish a measure of long-run marginal costs for various aspects of utility costs. If these costs are then passed on to ratepayers with minimal distortions (some distortions are needed for revenue recovery), then ratepayers will pay cost-reflective prices that enable them to make optimal decisions. (Ex. 29 A at 15; Ex. 30A at 15).

99. NV Energy states that it proposes two new rate designs. The first is a three-part rate where the demand and energy charges do not have a TOU component. The second is also a

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[25] Smart meters are capable of recording advanced billing functions such as incremental consumption and demand, thereby removing a large barrier/cost to the dissemination of cost-reflective rates. (Ex. 29A at 9; Ex. 30A at 9.)
[26] Approximately 99 percent of residential ratepayers have chosen the flat rate and 1 percent have chosen the volumetric rate. (Ex. 29A at 11; Ex. 30A at 11.)

three-part rate, but its demand and energy charges have a TOU component. Both are shown below for each of NPC's and SPPC's proposed NEM ratepayer classes:

NPC	RS		
Rates	Current Flat	NEM Flat	NEM TOU
Basic Service Charge	$12.75	$18.15	$18.15
Generation Meter*		$1.43	$1.43
Max Demand Rate ($/kW)		$14.33	$4.04
Summer On Peak Demand Rate ($/kW)			$22.15
Flat kWh Rate ($/kW)	$0.11642	$0.05470	
TOU kWh Rate ($/kWh)			
Summer On			$0.09147
Summer Off			$0.05016
Winter			$0.04727

NPC	RM		
Rates	Current Flat	NEM Flat	NEM TOU
Basic Service Charge	$9.00	$11.22	$11.22
Generation Meter*		$1.40	$1.40
Max Demand Rate ($/kW)		$13.95	$3.97
Summer On Peak Demand Rate ($/kW)			$24.39
Flat kWh Rate ($/kW)	$0.10939	$0.05648	
TOU kWh Rate ($/kWh)			
Summer On			$0.11491
Summer Off			$0.05787
Winter			$0.04727

NPC	LRS		
Rates	Current Flat	NEM Flat	NEM TOU
Basic Service Charge	$82.50	$78.86	$78.86
Generation Meter*		$8.98	$8.98
Max Demand Rate ($/kW)		$14.84	$4.11
Summer On Peak Demand Rate ($/kW)			$28.54
Flat kWh Rate ($/kW)	$0.10955	$0.05358	
TOU kWh Rate ($/kWh)			
Summer On			$0.09046
Summer Off			$0.05547
Winter			$0.04727

NPC	GS		
Rates	Current Flat	NEM Flat	NEM TOU
Basic Service Charge	$27.50	$35.43	$35.43
Generation Meter*		$7.57	$7.57
Max Demand Rate ($/kW)		$15.27	$4.72
Summer On Peak Demand Rate ($/kW)			$28.27
Flat kWh Rate ($/kW)	$0.07335	$0.04960	
TOU kWh Rate ($/kWh)			
Summer On			$0.06653

Summer Off			$0.05049
Winter			$0.04695
*Generation Meter Charge is waived for SolarGenerations customers.			

(See Ex. 2A at 48.)

SPPC	D-1		
Rates	Current Flat	NEM Flat	NEM TOU
Basic Service Charge	$15.25	$24.50	$24.50
Generation Meter*		$1.12	$1.12
Max Demand Rate ($/kW)		$8.63	$4.46
TOU Demand Rate ($/kW)			
Summer On Peak Demand Rate ($/kW)			$14.66
Winter On Peak Demand Rate ($/kW)			$1.43
Flat kWh Rate ($/kW)	$0.09842	$0.04749	
TOU kWh Rate ($/kWh)			
Summer On			$0.08694
Summer Mid			$0.05934
Summer Off			$0.04302
Winter On			$0.05036
Winter Off			$0.04302
SPPC	**DM-1**		
Rates	Current Flat	NEM Flat	NEM TOU
Basic Service Charge	$7.50	$10.75	$10.75
Generation Meter*		$1.12	$1.12
Max Demand Rate ($/kW)		$7.36	$3.70
TOU Demand Rate ($/kW)			
Summer On Peak Demand Rate ($/kW)			$12.71
Winter On Peak Demand Rate ($/kW)			$1.44
Flat kWh Rate ($/kW)	$0.08911	$0.04569	
TOU kWh Rate ($/kWh)			
Summer On			$0.10639
Summer Mid			$0.05611
Summer Off			$0.04077
Winter On			$0.04994
Winter Off			$0.04077
SPPC	**GS-1**		
Rates	Current Flat	NEM Flat	NEM TOU
Basic Service Charge	$32.00	$39.00	$39.00
Generation Meter*	$2.40	$4.67	$4.67
Max Demand Rate ($/kW)		$11.07	$5.53
TOU Demand Rate ($/kW)			
Summer On Peak Demand Rate ($/kW)			$15.13
Winter On Peak Demand Rate ($/kW)			$1.94
Flat kWh Rate ($/kW)	$0.08471	$0.04462	
TOU kWh Rate ($/kWh)			
Summer On			$0.08466
Summer Mid			$0.05687
Summer Off			$0.04221
Winter On			$0.04975
Winter Off			$0.04221
*Generation Meter Charge is waived for SolarGenerations customers.			

(Ex. 5A at 48). The three-part rates directly reflect the different cost elements from the MCSS, scaled so as to recover the revenue requirement. The numerical parameters of the rates should be updated periodically in a general rate case to reflect changes in the marginal costs and loads that determine the rates. Structurally, the rates should remain unchanged unless it is shown that the three-part rate no longer adequately reflects the underlying cost elements. Any excess production from the NEM system is credited for the excess kWh production. This credit goes into a "bank" account, which is used to pay for kWh consumption either in the current or future billing period. (Ex. 2A at 87-89; Ex. 5A at 84-86; Ex. 29A at 13-14; Ex. 30A at 13-14.)

100. NV Energy states that the proposed rate design recovers the cost of banking from the other non-NEM ratepayer classes. The cost of banking is created by NV Energy not recovering the commodity costs (i.e., energy and 38 percent of generation) associated with the banked energy returned to the NEM ratepayers. NV Energy proposes to collect the lost revenue from the other ratepayer classes. The revenues are allocated to the other ratepayer classes using the classes' marginal generation and energy allocation. (Ex. 2A at 45, 47, 163, 187; Ex. 5A at 45, 47, 159, 174.)

101. NV Energy states that the three-part rate design is consistent with the principles of cost-causation and largely eliminates subsidies from non-NEM to NEM ratepayers as required by Section 2.3(2)(e) of SB 374. In accordance with Section 4.5 of SB 374, the rates include a basic service charge that reflects marginal fixed costs incurred by NV Energy to serve NEM ratepayers, a demand charge that reflects the marginal demand costs incurred by NV Energy to serve NEM ratepayers, and an energy charge that reflects the marginal energy costs incurred by NV Energy to serve NEM ratepayers. (Ex. 29A at 16-17; Ex. 30A at 16-17.)

102. NV Energy recommends the Commission keep the existing NEM rules and rate

structures for NEM1 ratepayers, whose NEM applications were accepted or approved prior to the 235MW capacity cap being met. NV Energy also recommends the Commission approve new rules and rates for NEM2 ratepayers, whose NEM applications are accepted or approved after the 235MW capacity cap is met. (Ex. 2A at 5, 14, 88; Ex. 5A at 5, 14, 85.)

BCP Position

103. BCP recommends that the Commission reject NV Energy's proposal for residential and small commercial demand charges. No changes should be made to the rate design for NEM ratepayers between general rate cases unless the Commission finds that there is some unreasonable cost shift. NV Energy has not provided information on the usage of ordinary residential ratepayers to allow the determination of whether rates with demand charges are biased by usage levels due to different levels of coincidence between ratepayer demand and maximum demand. If the issue is pursued at all, it should be pursued in a general rate case. (Ex. 62A at 3, 9-10.)

104. BCP states that demand charges have the fundamental problem of charging a ratepayer who uses power for a limited period of time the same amount as a ratepayer who uses large volumes of power throughout an entire peak period. Demand charges are both unknown to residential ratepayers and complicated to explain. NV Energy could end up with serious customer relations problems if it designs a demand charge in a way that ratepayers see as punitive and then do not provide adequate information to ratepayers. (Ex. 62A at 10-11.)

105. BCP states that any demand charge should be measured based on an hour interval instead of fifteen minutes. Individual residential ratepayers have relatively random patterns of energy use and thus have less coincidence with peak, compared to large industrial ratepayers. With a fifteen-minute demand charge, random events having little or nothing to do with cost

causation could trigger a significant demand charge. Many of those random spikes (i.e. turning on a hair dryer, a microwave, and a toaster at the same time) are at least partly dampened over an hour. As an example, Arizona Public Service's residential demand charges are based on an hour, not 15 minutes. (Ex. 62A at 11.)

106. BCP states that if a demand charge is adopted, there should be a period of time before it is put into effect when ratepayers should be provided education on what a demand charge is, how it works, and how to reduce it. Otherwise, the demand charge shift could be seen as a ploy to put money in shareholders' pockets while profiting from ratepayers' inattention to details that ratepayers never had to understand or consider before. (Ex. 62A at 11-12.)

107. BCP states that the Commission should not change the cost of energy delivered by NV Energy until the next general rate cases where there will be comprehensive MCSS performed. By not making changes to the cost of energy delivered, the Commission will also not be using MCSS with arbitrary load assumptions mixed with different load assumptions for other ratepayer classes and will not single out NEM ratepayers for extremely high facilities charges that the BCP believes are inappropriate for all residential ratepayers. On the other hand, BCP states that it believes that the Commission should reduce the rate paid for banked kWh to exclude 80 percent of the distribution volumetric rate because the amount associated with substations and high voltage distribution is about 10-25 percent of the volumetric rate, depending on the utility, and some portion of upstream feeders near the substation is avoidable by diversified demand. NV Energy should be required to make a compliance filing on this issue based on current levels of costs. (Ex. 62A at 12.)

108. BCP states that NEM ratepayers should not be placed on current TOU rates in the near term. It is possible that time periods will shift in the future due to more utility-scale solar

plants coming on line, so providing both NEM and the current TOU periods may over-assign benefits to these ratepayers. (Ex. 62A at 13; Tr. at 446-447.)

109. BCP states that NEM1 ratepayers should be grandfathered for a period of at least 8-10 years (roughly equivalent to the payback period for NEM system investments) to assure that investments are recovered over that time period. (Tr. at 444-445.)

Bombard Position

110. Bombard recommends TOU rates for NEM ratepayers. NV Energy's kWh to kWh credit provides NEM ratepayers with an actual dollar value for a net-metered kWh. If a NEM ratepayer then is required to participate in the corresponding optional TOU ratepayer class, this will allow prospective NEM ratepayers to accurately predict the value of a prospective NEM system and make an informed decision as to whether proceeding with such a NEM system is worthwhile for the ratepayer. TOU rates are fair because such rates helps the NEM ratepayer understand the value of each kWh based upon when it is produced. (Ex. 59A at 2-3.)

111. Bombard states that NEM ratepayers need a rate design that is simple to understand. Layering on unjustified and hard-to-understand demand charges and other large fixed charges will confuse NEM ratepayers. (Ex. 59A at 2.)

112. Bombard states that a demand charge is not warranted for NEM ratepayers who do not currently have a demand charge because NEM ratepayers do not increase their demand relative to other ratepayers in the same rate class. In fact, when a ratepayer installs a NEM system, ratepayer demand does not increase but rather decreases during the times that the NEM system produces energy.

113. Bombard states that it supports the Commission doing what is best for the ratepayers of Nevada regarding grandfathering. (Tr. at 415.)

SEIA Position

114. SEIA states that the imposition of a demand charge on NEM ratepayers is not common. Several jurisdictions have considered but not ultimately imposed demand charges. Only three utilities have adopted such capacity-based charges—Salt River Project (Arizona), Santee Cooper (South Carolina), and WE Energy (Wisconsin). When the Salt River Project implemented a demand charge (coinciding with the sunset of a small incentive), applications for NEM service dropped by 95 percent. (Ex. 45A at 5-11.)

115. SEIA states that imposing a demand charge on NEM ratepayers would deter the continued growth of NEM systems. Fewer people will participate in NEM service, slowing the continually dropping price of NEM systems. A demand charge adds confusion because it is difficult to predict and calculate the savings that would come from a NEM system, dissuading many from electing to install a NEM system on their homes. A reduction in the number of future NEM system installations would also have a significant impact on the number of rooftop solar jobs in Nevada. (Ex. 45A at 11.)

116. SEIA states that imposing a demand charge would also affect Nevada's homebuilding industry. Rooftop solar is increasingly becoming an important tool in meeting energy efficiency standards in strict new building codes as homebuilders opt for rooftop solar systems instead of more expensive building materials to meet modern code requirements. (Ex. 45A at 11.)

117. SEIA states that if any changes are made to the NEM tariffs, such changes should only be effective for new NEM ratepayers as of the date of the final decision in this proceeding. Ratepayers who signed up for the NEM tariff under the 235 MW cap have the expectation that NEM would be available to them and additional fees would not be imposed. It is important that

ratepayers have transparency and predictability in their rates, and NEM ratepayers entered into NEM agreements with this understanding and expectation. Further, business models and industries have been structured around the expectation that past policies would remain consistent. Fundamental changes in regulation can irreversibly harm these industries, which employ thousands of Nevadans, provide ratepayers with innovative energy services, and benefit the environment. (Ex. 45A at 12.)

SNHBA Position

118. SNHBA states that a flat rate has worked well to date because it is easy to understand. Adding a new and untested demand charge, as proposed by NV Energy, will not achieve a level of simplicity that resonates with the average residential ratepayer. Simplicity is a critical element for customer adoption. However, if the Commission ultimately decides to include a demand charge, it should be applied equally to all residential ratepayers because non-NEM ratepayers are primarily responsible for the large capacity costs associated with peak summer loads. Equal applicability is particularly important to homebuilders who will otherwise have difficulty explaining to prospective homebuyers why NEM ratepayers automatically get high demand charges while non-NEM ratepayers do not. One of SNHBA's largest members has already lost two home sales as a result of trying to explain NV Energy's rate design proposal. NV Energy's proposal, as currently structured, will have a negative impact on NEM ratepayers. (Ex. 41A at 6-8, 18.)

119. SNHBA states that the financial impacts of NV Energy's TOU option are untested and more than likely not understood by most ratepayers. (Ex. 41A at 6.)

Staff Position

120. Staff recommends that the Commission find that it is in the public interest to

establish and impose a new NEM rate structure with rates to be updated in NV Energy's subsequent general rate cases. Staff is sufficiently uncomfortable with the inputs and analysis underlying NV Energy's MCSS that Staff does not rely on them to calculate the proposed rates and cautions the Commission from relying on them to set rates. Instead, Staff looks back to the last approved MCSS from the general rate cases for NV Energy. This method, at a minimum, avoids the problem of using different MCSS to set rates for different ratepayer classes. Staff reviewed net metering dockets in Hawaii, Massachusetts, South Carolina, Minnesota, Ohio, Oregon, and Texas in developing its proposed NEM rate structure. (Ex. 64A at 1, 13.)

121. Staff recommends a buy/sell arrangement whereby the provision of electricity is governed by the results of the MCSS from the last general rate cases, but adjusted to recover a larger portion of the fixed customer, facility, and demand costs in the basic service charge. The use of energy produced by the NEM system by the NEM ratepayer on-site is not charged or credited. The net credit for excess generation by the NEM ratepayer back onto the utility's grid will be in accordance with the avoided costs. (Ex. 64A at 13-14.)

122. Staff recommends that the Commission set the basic service charge rates to recover the full amount of customer, facilities, and primary and high voltage distribution costs that were discussed in NV Energy's last general rate cases. Staff provides a comparison of the current and proposed basic service charge rates as follows:

Class	Current BSC	NPC Proposed BSC	Staff Proposed BSC
RM	$9.00	$18.15	$16.24
RS	$12.75	$18.15	$33.31
LRS	$82.50	$78.86	$238.32
GS	$27.50	$35.43	$31.04

Class	Current BSC	SPPC Proposed BSC	Staff Proposed BSC
DM-1	$7.50	$10.75	$15.46
D-1	$15.25	$24.50	$32.97

GS-1	$32.00	$39.00	$53.52

This is the simplest and most easily understood method to recover primarily fixed charges through a fixed rate. (Ex. 64A at 14-16.)

123. Staff recommends that the Commission not impose a demand charge for NEM ratepayers. Once the NEM ratepayer classes are established, over time NV Energy could propose to implement demand charges as part of a general rate case, and Staff and interested parties could review the proposals at that time. However, if the Commission believes that demand charges are appropriate now for NEM ratepayers, Staff recommends that the Commission use the basic service charge and demand charges that are contained in NV Energy's respective Schedule SSR tariffs, which incorporate a ratepayer's otherwise applicable rate schedule and are also similarly based on the last approved MCSS and billing determinants from the last general rate case. Alternatively, the Commission can determine the appropriate rate tilt to use for NEM ratepayer classes, consistent with the rate tilt of larger ratepayer classes and apply the same factors to the percentage recovery of these costs in the fixed charges and the demand charges for the NEM ratepayer classes. NV Energy would have to file these work papers as a compliance to be checked by Staff for accuracy and compliance with the Commission's order. Either method would be consistent with past Commission practices and ratemaking. (Ex. 64A at 15-17.)

124. Staff states that because 100 percent of the customer, facilities, and primary and high voltage distribution costs would be recovered in the fixed basic service charge under Staff's proposal, the base tariff general rate ("BTGR") would need to change correspondingly. Using a fully compensatory basic service charge and the previously approved MCSS and allocations, there should be no cost or revenue shifting for NEM and non-NEM ratepayers between general

rate cases. This method yields much lower BTGRs for the NEM ratepayers because more of the fixed costs are being recovered in the fixed charges. In the next general rate case, the NEM ratepayer classes will be allocated their share of the functionalized costs, and NV Energy will use the billing determinants for those classes to set the rates for the next cycle. This analysis will occur in each subsequent general rate case, and as costs or usage change, those factors will correspondingly change and be reflected in the rates of the NEM classes. (Ex. 64A at 16).

125. Staff recommends that the Commission set a value for the NEM ratepayers' excess generation that captures the majority of the variables that make up the possible value/detriment of NEM. The value of NEM changes over time based on a variety of factors—relative location and concentration, natural gas prices, and the price of utility-scale renewables amongst other things. Consequently, setting a fixed value for a long period of time is unwise. The Commission can set a value during each general rate case by using a methodology similar to the one stipulated to in South Carolina. In short, the methodology considers both the positive and negative effects of: (1) avoided energy; (2) energy losses/line losses; (3) avoided capacity; (4) ancillary services; (5) transmission and distribution capacity; (6) avoided criteria pollutants; (7) avoided CO2 emission cost; (8) fuel hedging; (9) utility integration and interconnection costs; (10) utility administration costs; (11) environmental costs. The value to NV Energy and the ratepayers is the avoided, incremental cost forgone by the utility by acquiring the net excess generation from the NEM system. Consequently, Staff proposes to use the average annual long-term avoided energy cost that is forecasted by PROMOD from NV Energy's last approved integrated resource plan filings with an adder for avoided distribution line losses. NV Energy should account for this monthly credit on NEM ratepayers' bills as a fuel and purchased power expense which would go into the base tariff energy rate ("BTER") and deferred energy account

adjustment ("DEAA") accounts accordingly. There is insufficient time or data in this proceeding to assign a value to the other nine variables, but other information can be vetted in future general rate cases. (Ex. 64A at 17-19; Tr. at 539-540.)

126. Staff recommends using the value of $26.51 per MWh for NPC's rate and $26.93 per MWh for SPPC's rate to credit hourly excess generation for 2016. Staff took the average monthly long-term avoided costs for NV Energy in Docket No. 15-07004 and averaged the monthly avoided costs to calculate an annual rate of $25.84 for 2016 and $28.82 for 2017. NV Energy's Portfolio Pro software (used to determine the costs and benefits of a demand-side management program) uses an average line loss (for transmission and distribution) of 4.2 percent for NPC and 5.8 percent for SPPC. In NV Energy's last Federal Energy Regulatory Commission rate case, NV Energy testified that the average transmission loss was 1.57 percent. Thus, subtracting the transmission losses from those figures results in distribution line losses of 2.63 percent for NPC and 4.23 percent for SPPC, which are used to gross up the annual rate to get the value of the excess generation. One would use the same chart and line loss factors for each subsequent year until a new integrated resource plan is filed, at which time the Commission would adopt the new rates as part of its next general rate case. (Ex. 64A at 18-19.)

127. Staff states that there are other options the Commission can use to value the excess generation. Precision is always better, but it is not always necessary if the same goal can be achieved in large part by using an average price. First, the Commission could use an average of the daily Powerdex prices for each of the utilities. Second, the Commission could use real-time Powerdex average prices, which would only be posted after the fact. Third, the Commission could use the value of the lowest last-approved renewable PPA, minus the portfolio energy credit value, putting NEM on par with utility-scale solar generation ($36.11 per MWh for

NPC and $36.68 per MWh for SPPC after gross-up for avoided line losses). Fourth, the Commission could credit the excess generation at the same rate as the BTER if the Commission wished to be generous and simply average the value of the entire energy portfolio. (Ex. 64A at 20; Tr. at 464-469.)

128. Staff recommends that the Commission allow NEM ratepayers to choose whether to take service under the NEM rate or NEM TOU rate. The NEM TOU rate would be the same as the otherwise applicable ratepayer class's TOU rate. Using these rates is a consistent and reasonable choice because the TOU rates have been calculated and adopted using the last approved MCSS and the Commission approved those rates as being just and reasonable to use to value usage at different times of the day. As usage and load factors and profiles change, those ratepayers who choose NEM TOU will see a reflection of those factors in the rates at subsequent general rate cases. (Ex. 68A at 21.)

129. Staff disagrees with NV Energy's proposed banking of excess credits and the proposed recovery of value of those credits. Non-NEM ratepayers are still paying the rates that incorporate the costs of generation without being adjusted for the benefits of offsetting generation and energy costs as NV Energy claims. It is not appropriate to request that non-NEM ratepayers pay for this banking. The appropriate forum to address this topic is in a general rate case where all ratepayer classes are represented. (Ex. 82A at 10-11.)

130. Staff states that NV Energy should endeavor to use consistent rate design for all ratepayer classes. While NV Energy proposes a demand charge for residential NEM ratepayers, residential ratepayers have not had a demand cost recovery component in the past. Further, the proposed amount of rate tilt for NEM ratepayers is different. Rate tilt refers to how a cost is recovered. In the past, the Commission has utilized its authority to design rates and shift (tilt)

some fixed and demand costs to be recovered through a volumetric commodity rate. One of the underlying principles of rate design is to have a consistent methodology in calculating rates. By being consistent, rates should, in theory, not fluctuate too much between general rate cases. However, an argument can be made that because NV Energy states that NEM ratepayers are partial-requirements ratepayers, a deviation in rate tilt is required in the collection of costs from different rate components. As long as the NEM ratepayers are in different classes, over time the Commission can strive for consistency in the applicability of those rates. (Ex. 82A at 2, 11-12.)

131. Staff recommends that the Commission find that it is in the public interest to apply the new NEM rate structure to all NEM ratepayers or, at a minimum, set a time limit for the "grandfathering" of those NEM ratepayers that participated under the 235 MW cap. First, Section 2.3(3) of SB 374 plainly provides that the Commission may determine in this proceeding whether grandfathering of NEM1 ratepayers should occur. Second, NV Energy is generally not allowed to discriminate between similarly-situated ratepayers but is allowed to differentiate between classes of ratepayers if either the costs to serve or the usage patterns are sufficiently different. The ratemaking principle of horizontal equity supports treating equals (NEM ratepayers) equally. Third, Staff does not believe it is appropriate to use NEM1 data (as NV Energy used for a proxy group because no data exists for NEM2 ratepayers yet) to establish NEM2 rates and then not apply those same rates to NEM1 ratepayers. Fourth, Staff's proposal gives all ratepayers the ability to choose to install NEM systems and choose whether to elect the NEM or TOU rates. Fifth, Staff's proposal provides a more accurate signal of the value of excess generation to all NEM ratepayers. Providing different price signals to similar ratepayers is illogical and potentially confusing. Sixth, it is impractical to track different generations of ratepayers, especially if circumstances change (ie. Does the rate structure stay with the account,

stay with the premise, or stay with the ratepayer? What if the NEM system fails?; What if more panels are added to the NEM system?). Seventh, lawsuits alleging antitrust matters have been filed in other jurisdictions for differential treatment of NEM ratepayers. (Ex. 64A at 1-2, 22-25.)

132. Staff states that it is concerned for the NEM1 ratepayers who were sold/leased NEM systems based on assumptions that turn out to be incorrect. However, most ratepayers understand the fundamental principle that utility rates are all subject to change over time. There was no representation or guarantee from the Legislature, NV Energy, or the Commission that the NEM framework would continue in its original form in perpetuity. Sales offerings that are made by rooftop solar installers are not within Staff's or the Commission's control. The Commission changes utility rates frequently, and no other set or subset of ratepayers is shielded from those changes. Sending a more accurate price and value signal through Staff's proposed rate structure is more important than shielding a subset of ratepayers from changes in utility rates. (Ex. 64A at 25-26.)

133. Staff states that if the Commission disagrees with Staff's recommendation and allows grandfathering of NEM1 ratepayers, Staff recommends that the Commission limit the timeframe in which to grandfather NEM1 ratepayers, such as four years for SPPC ratepayers and five years for NPC ratepayers to be consistent with the general rate case cycles of both utilities, and then move those ratepayers to the NEM2 rates at the end of that time period as rates are changed and calculated for all classes. Grandfathering NEM ratepayers indefinitely is not reasonable because the NEM systems are not indefinite themselves and will eventually need to be replaced. As a result, NV Energy may not know if/when the NEM systems are replaced, which could result in a special rate in perpetuity. (Ex. 64A at 25-26.)

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TASC Position

134. TASC recommends that the Commission reject NV Energy's proposed NEM2 rates and direct NV Energy to continue to provide NEM at existing retail rates for residential and small commercial ratepayers, as is now the practice under NEM1. To the extent that the NV Energy NEM program results in additional costs, those costs can be collected from NEM ratepayers through interconnection and application fees. This will prevent any unreasonable cost-shifting, consistent with SB 374. (Ex. 76A at 25.)

135. TASC states that in passing SB 374 (and in particular Section 2.8), the Legislature reaffirmed that the purposes of NEM in Nevada are to do the following:

> 1. Encourage private investment in renewable energy resources;
> 2. Stimulate the economic growth of this State;
> 3. Enhance the continued diversification of the energy resources used in this State; and
> 4. Streamline the process for customers of a utility to apply for and install net metering systems.

These goals clearly indicate that the Legislature intended for NEM service to continue to grow as a viable energy resource for Nevada and for customers to have NEM service as a reasonable choice to provide for a portion of their electricity needs. Unless NEM service remains viable, customers will not make private investments in NEM systems, the rooftop solar industry will not contribute to Nevada's economic growth, and the opportunity to diversify Nevada's energy resources with clean, local, distributed solar generation will be lost. (Ex. 49A at 6; Ex. 76A at 3-4.)

136. TASC states that ratemaking and rate design decisions are typically based on many factors, not all of which can be quantified. Rate design is not a simple mechanical process. In designing rates, several ratemaking principles should be considered. In Principles of Public Utility Rates, Professor James Bonbright discusses eight key criteria for a sound rate structure:

> 1. The related "practical" attributes of simplicity, understandability, public acceptability , and feasibility of application;
> 2. Freedom from controversies as to proper interpretation;
> 3. Effectiveness in yielding total revenue requirements under the fair-return standard;
> 4. Revenue stability from year to year;
> 5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers;
> 6. Fairness of the specific rates in the appointment of total costs of service among the different customers;
> 7. Avoidance of "undue discrimination" in rate relationships;
> 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
> a. in control of the total amounts of service supplied by the company;
> b. in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.)

These principles have been recognized and used by Commissions throughout the country for many years. Sometimes these principles are in tension with each other, and Commissioners must strike the appropriate balance between these principles. Too much emphasis on any one can lead to undermining the other principles. (Ex. 49A at 20, 26-28.)

137. TASC states that NV Energy's proposed increased fixed charges and demand charges for NEM ratepayers fail to satisfy the principles of rate stability, efficiency, equity, and that of simplicity, understandability, public acceptability, and feasibility of application. NV Energy's proposal violates the principle of rate stability because it raises the customer charge by 42 percent and 61 percent for NPC and SPPC, respectively, and it shifts a significant portion of the ratepayer's bill to the demand charge. NV Energy's proposal violates the principle of efficiency because it reduces ratepayers' ability and incentive to reduce electricity consumption by reducing the energy charge. NV Energy's proposal violates the principle of equity because it creates significantly different rates for ratepayers whose costs are very similar (after corrections

are made to the MCSS). NV Energy's proposal violates the principles of simplicity, understandability, and customer acceptability because it introduces a rate structure (demand charges) that is difficult for residential ratepayers to understand and reduces ratepayers' control of their bills. Furthermore, NV Energy's proposal is inconsistent with recent decisions from commissions in several other states on this issue whereby requests for an increase in fixed charges have been rejected in whole or approved only in part. (Ex. 49A at 29-37.)

138. TASC states that the simplicity and understandability of the existing NEM rate structure is a significant benefit to ratepayers, NV Energy, and the Commission. Under the current structure, all NEM ratepayers continue to see exactly the same price signals from rate design as non-NEM ratepayers. Ratepayers find this easy to understand. This also means that NV Energy, the rooftop solar industry, and the Commission do not have to educate NEM ratepayers about rate design in any way that is different than with non-NEM ratepayers. Similarly, if Nevada were to decide to encourage more ratepayers to adopt TOU or Critical Peak Pricing rates, informing ratepayers about these new rate structures will be the same regardless of whether the ratepayer has a NEM system or not. (Ex. 76A at 10.)

139. TASC recommends that the Commission not adopt a demand charge as proposed by NV Energy. As seen in customer surveys from three major investor-owned electric utilities in California in 2013, demand charges will confuse ratepayers. Such confusion is not surprising given that demand data for typical home energy uses is not readily available—energy usage for home appliances is typically expressed in terms of the annual kWhs of energy use, not the maximum power use. Further, data on each residential ratepayer's maximum hourly demand for their home as a whole only became available recently with the advent of AMI. If a demand charge is adopted, NV Energy will need to undertake a comprehensive education program on the

demand charges that apply to a ratepayer who installs rooftop solar. This will also significantly complicate the sales process for rooftop solar companies, as ratepayers will have much greater difficulty understanding and trusting the salesperson's estimates because modeling savings under a demand charge structure would be much more complex. Such complex rate structures may be appropriate for large commercial, industrial, and institutional facilities, who understand both their TOU energy usage and their maximum monthly demand, have the metering to track both energy use and demand in real-time, and can pay facility managers dedicated to managing those demands and costs. Such a rate structure is not understandable or workable for residential or small commercial ratepayers who spend only a few minutes a month focused on their utility bills. (Ex. 76A at 6-10.)

140. TASC states that demand charges also present a significant barrier to the continued adoption of rooftop solar in Nevada and will not contribute to its sustainable growth as required by NRS 704.766. TASC states that NEM ratepayers will not be able to avoid the demand charges to the same extent as the current volumetric rates, as NV Energy's analysis shows. Because NV Energy's proposed NEM2 rates move significant costs from volumetric energy rates to demand charges, the energy rates assessed under NV Energy's NEM2 rates are approximately 60-65 percent of what they would be for existing NEM ratepayers, which results in a dramatic loss of bill savings. The bill savings from solar generation must offset the cost of the rooftop solar system within a reasonable payback period if solar generation is to be a viable and reasonable investment for the customer. (Ex. 76A at 4-5, 9.)

141. TASC states that the proposed demand charges are not cost-based. When ratepayers install rooftop solar systems, the ratepayers serve a significant portion of their load with their own on-site generation. This reduces NV Energy's costs to serve the NEM ratepayers

and provides new renewable capacity to the grid. Based on the hourly profile of marginal costs, the average NPC NEM ratepayer will reduce the utility's generation capacity costs by 42 percent and their transmission and distribution capacity costs by 45 percent. However, if a significant portion of NV Energy's costs for capacity-related generation, transmission, and distribution costs are collected through a demand charge, the ratepayers may see little reduction in their bills for the costs covered by the demand charge. NV Energy's data shows that the average NEM ratepayers will only reduce their bills by eight to nine percent with the proposed demand charge, whereas if the same capacity-related costs are recovered through a volumetric rate, the average NEM ratepayers will reduce their bills by 36 percent based on the difference between pre-solar total loads and post-solar delivered volumes. Therefore, a demand charge structure will under-compensate the average NEM ratepayer, allowing the NEM ratepayer to reduce bills by less than 20 percent of the amount of capacity-related costs that the ratepayer allows the utility to avoid, whereas a volumetric rate would allow the NEM ratepayer to reduce bills by more than 80 percent of the amount by which the utility's costs are reduced. (Ex. 76A at 11-17.)

142. TASC states that it is not cost-based to assess a demand charge on NEM ratepayers based on the NEM ratepayers' maximum use in any hour. The marginal capacity-related costs, which the utilities would include in the demand charge, are focused on the afternoon and early evening hours, not morning or nighttime hours. As a result, it is not reasonable to impose a demand charge on residential NEM ratepayers based on their maximum demand in any hour because such maximum demands may occur outside of the hours that drive the utilities' marginal costs. There is a level of diversity on residential circuits with many small ratepayers such that the utility does not have to plan to size residential circuits to serve the sum of the non-coincident demands of all residential ratepayers on the circuit. Such diversity does

not exist to the same extent on circuits serving larger ratepayers, thus non-coincident demand charges are more reasonably a part of commercial and industrial distribution rates. As a result, it would be reasonable to collect transmission and distribution costs from residential ratepayers based on their average demand over a summer on-peak TOU period that covers just the hours when the circuit is most likely to peak. This can be accomplished through a volumetric TOU charge to recover transmission and distribution costs during these peak hours. A ratepayer's kWh usage over the peak period measures the ratepayer's contribution to the average demand during those hours and would be a reasonable, cost-based charge. An even more accurate rate would be very high Critical Peak Pricing rates, which are volumetric TOU rates that charge very high on-peak rates to ratepayers in a limited number of high-demand hours each year that the utility or system operator declare on a day-ahead basis. Demand charges are increasingly obsolete because, with new metering technology, focused TOU rates will be much more accurate than traditional fifteen-minute demand charges. Some jurisdictions are replacing demand charges with TOU and Critical Peak Pricing rates. This represents a far more accurate, targeted, and cost-based means to charge ratepayers than the traditional fifteen-minute maximum demand charge. (Ex. 76A at 17-20.)

143. TASC states that the Salt River Project ("SRP") adopted a new NEM tariff that included significantly higher monthly fixed charges as well as demand charges. The impact of the new rate structure that is similar to, but not quite as onerous as what NV Energy has proposed, has been almost a complete shutdown of the rooftop solar market in SRP's service territory with a decline of 95 percent in the average number of NEM applications received each month compared to the previous year. (Ex. 49A at 8-9; Ex. 76A at 20-24.)

144. TASC states that NV Energy has admitted that under the proposed NEM2 rates, a

ratepayer who wishes to install a NEM system will have to pay a premium to continue service from the utility when one considers both the NEM2 rate and the cost of a rooftop solar system. Very few, if any, ratepayers would be willing to lease or purchase NEM systems if the end result is to simply increase their total energy costs.[27] There is no question that such an outcome would be inconsistent with the clear intent of SB 374 to encourage private development of renewable resources, stimulate economic growth in Nevada, and enhance the diversification of Nevada's energy resources. (Ex. 49A at 7-8.)

145. TASC recommends that interim NEM ratepayers that apply for interconnections prior to the Commission issuing an order on NEM2 rates and NEM1 ratepayers who have taken service below the 235MW cap should be grandfathered under the NEM1 rates and tariffs. Through the end of 2015, NEM ratepayers who receive incentives through the SolarGenerations program will provide NV Energy with RECs with a 2.45x multiplier. These multiplied RECs will have significant additional value to NV Energy for RPS compliance. The Commission should also recognize that existing NEM ratepayers have made long-term commitments to NEM systems in reliance on existing rates and with the encouragement of the existing incentive program, albeit under conditions of substantial uncertainty. Any issues pertaining to changed circumstances with the NEM systems can be worked out fairly easily. Finally, TASC fully recognizes that when NEM ratepayers decide to install systems under a NEM tariff, they bear the risks and rewards over time of typical changes to the levels and designs of utility rates. However, the 35-40 percent rate increase proposed by NV Energy is truly extraordinary and far beyond what is typical through the normal ratemaking process. (Ex. 45A at 31-32; Tr. at 309-

[27] Currently, SPPC's Green Energy Choice program allows ratepayers to pay a premium (similar to the reduction in bill savings for NEM ratepayers from the proposed NEM 2 rate) to increase the percentage of renewable energy that serves them. As of the end of 2014, just 15 residential ratepayers and 2 small commercial ratepayers have signed up for this program. (Ex. 76A at 24.)

313.)

146. TASC also recommends that NEM2 ratepayers who take service after December 31, 2015, should take service under the existing NEM1 rates because the NEM2 rate design will not impact other ratepayers until new rates take effect after the general rate cases are complete. The NEM2 rate design will do nothing until the next general rate case to remedy any perceived cost shifting because the increased revenues during the interim period will flow to NV Energy shareholders at a time when NV Energy has earned approximately $33.5 million, as of March 2015, in excess of its authorized rate of return. After revised NEM2 rates have been approved in the next general rate cases, the NEM2 ratepayers can move to the permanent NEM2 rates. (Ex. 45A at 32, 49-50.)

WCSD Position

147. WCSD recommends that the rules governing NEM1 systems remain unchanged. WCSD has 39 NEM systems at its facilities. WCSD made investments in NEM systems based on encouragement from the Nevada Legislature and SPPC to install systems on schools for educational benefits and operational cost savings. The investments were made based on cost estimates and projected savings to WCSD for the 20-year commitment required to participate in the SolarGenerations program. The cost savings associated with the NEM systems have resulted in lower electrical costs to WCSD that are then utilized for other educational expenses. Any changes to NEM1 tariffs could have a negative consequence on WCSD. (Ex. 40A at 2, 4-5.)

Vote Solar Position

148. Vote Solar recommends that the Commission reject NV Energy's proposed rates and tariffs and permit NEM2 ratepayers to continue to take service under current rates. (Ex. 44A at 5.)

149. Vote Solar states that the Nevada Legislature made clear in section 2.8 of SB 374 that the purpose and policy in requiring that utilities offer NEM to ratepayers is to: (1) encourage private investment in renewable resources; (2) stimulate the economic growth of Nevada; (3) enhance the continued diversification of the energy resources used in Nevada; and (4) streamline the process for ratepayers of a utility to apply for and install NEM systems. It is important for the Commission to keep this purpose and policy in mind when reviewing the NEM proposals in this proceeding. (Ex. 44A at 8.)

150. Vote Solar states that the proposed tariffs do not reflect marginal costs as required by SB 374. NV Energy's demand, energy, and customer rates in its proposed tariffs do not reflect marginal costs, but rather reflect NV Energy's embedded revenue requirement. NV Energy prorates the result of the MCSS to the respective utility's revenue requirement. The MCSS serve only to allocate the costs that are reflected in the revenue requirements. Thus, it is the revenue requirements, not marginal costs, which are reflected in NV Energy's proposed rates. Because the cost of the next unit of service to the system often exceeds, and is certainly different than, the current average cost of service, NV Energy cannot base its proposed charges for its NEM tariffs on marginal costs and recover the proper cost of service. It is a reasonable approach for the purpose of assuring that the rates in effect do not allow the utility to over earn, however, the rates developed are not reflective of marginal cots and do not comply with SB 374. Marginal costs can be used as the primary price signal for periods of higher costs, if balanced by lower prices during periods of lower costs. A good example of this approach is TOU rates in which pricing for the peak periods reflects marginal costs. (Ex. 44A at 46-51.)

151. Vote Solar states that the Commission should not approve a demand charge component in NEM rates. Demand charges may be appropriate for large commercial and

industrial ratepayers that are able to manage their energy and peak demand levels but are wholly inappropriate for small ratepayers who have little ability to manage the peak demand upon which demand charges are based. Solar rooftop installations have little effect on a ratepayer's peak demand, regardless of orientation. With peak demand charges based on a fifteen-minute interval, the shading provided by afternoon clouds that often appear in the desert Southwest is sufficient to reduce solar generation long enough for the ratepayer to set a peak as it only has to happen once in a 30-day time period. Randomly timed demand charges do not send appropriate price signals to encourage ratepayers to move load off-peak. As a practical matter, there are only two ways to reduce peak demand, either through behavioral changes or through advanced technologies such as timing of certain appliance usage or integrating storage technologies. Both require ratepayers to fully understand their daily load patterns. While it is a relatively simple matter for a small ratepayer to use, or avoid using, electricity during certain hours of the day, it has no way of knowing when the fifteen-minute interval may occur so that it can reduce its demand for the entire period. Further, a demand charge would not send a proper price signal to NEM ratepayers. A price signal is one for which the customer has an ability to respond. If the customer is unable to respond, particularly using the technology driving the utility's desire for the new charge, then the demand charge simply acts as a fixed charge. Finally, batteries and other forms of storage are already in use by larger ratepayers to mitigate the effects of demand charges. To the extent that storage technologies follow a similar cost curve as have some solar technologies and use of storage becomes more ubiquitous over the next few years, there is a risk that NV Energy will again seek changes to rates and rate structures that will make that new technology less cost-effective for ratepayers. (Ex. 44A at 10-11, 53-59.)

152. Vote Solar states that demand charges have been demonstrated to have a negative

impact on the market for rooftop solar resources. SRP saw a 95 percent drop in rooftop solar applications after it required a demand charge for new residential solar ratepayers. Here, the main driver of the bill increase from NEM1 to NEM2 is the demand charge. So singling out NEM ratepayers and subjecting them to these demand charges would not encourage private investment in renewable energy resources. (Ex. 44A at 10-11, 52-53.)

153. Vote Solar states that separate ratepayer classes for NEM2 ratepayers with rates and charges that include a demand charge add costs to the opportunity to become a customer-generator, making such an investment less economic. Making the investment less economical will discourage private investment in renewable energy resources and reduce the growth of distributed solar energy and related economic growth in Nevada. (Ex. 44A at 60.)

154. Vote Solar recommends that in an effort to continue to gather information to help inform the Commission on future potential rate designs, the Commission should implement an alternate TOU tariff through shadow billing. TOU rates are now an option that can be considered by the Commission (see Section 2.5 of SB 374). TOU rates can be structured such that peak period pricing reflects the marginal costs of providing service to NEM ratepayers as required by SB 374. Vote Solar developed a conceptual framework for a TOU tariff (for NPC only) based upon the time when electricity is consumed, the current TOU periods in NPC's tariffs, and the marginal cost for the on-peak period as follows:

	RS-NEM	RM-NEM	GS-NEM
Monthly Customer Charge	$15.93	$8.95	$26.14
Summer on-peak	$0.13400	$0.10387	$0.08901
Summer off-peak	$0.11146	$0.09712	$0.08190
All other hours	$0.10575	$0.09222	$0.07754

Shadow billing with TOU rates will allow NV Energy and NEM ratepayers to gain a better understanding of the effects of a marginal cost-based rate before any such rate would go into effect. Additionally, NV Energy will be able to use consistent time periods for the studies. (Ex. 44A at 5, 61-64.)

NV Energy Rebuttal Position

155. NV Energy continues to recommend a three-part rate structure for NEM2 ratepayers based on the results of the MCSS. NV Energy states that it has modifications that should be incorporated into NPC's proposal. There was a linking error in the MCSS that affected the marginal energy costs. There were three errors pertaining to the present rate revenue calculations. The modified rates are as follows:

NPC	**RS**			
Rates	NEM Flat	NEM TOU	Revised NEM Flat	Revised NEM TOU
Basic Service Charge	$18.15	$18.15	$18.13	$18.13
Generation Meter*	$1.43	$1.43	$1.43	$1.43
Max Demand Rate ($/kW)	$14.33	$4.04	$14.30	$4.03
Summer On Peak Demand Rate ($/kW)		$22.15		$22.10
Flat kWh Rate ($/kW)	$0.05470		$0.05458	
TOU kWh Rate ($/kWh)				
Summer On		$0.09147		$0.09097
Summer Off		$0.05016		$0.05006
Winter		$0.04727		$0.04727
NPC	**RM**			
Rates	NEM Flat	NEM TOU	Revised NEM Flat	Revised NEM TOU
Basic Service Charge	$11.22	$11.22	$11.20	$11.20
Generation Meter*	$1.40	$1.40	$1.40	$1.40
Max Demand Rate ($/kW)	$13.95	$3.97	$13.91	$3.96
Summer On Peak Demand Rate ($/kW)		$24.39		$24.33
Flat kWh Rate ($/kW)	$0.05648		$0.05643	
TOU kWh Rate ($/kWh)				
Summer On		$0.11491		$0.11437
Summer Off		$0.05787		$0.05780
Winter		$0.04727		$0.04727
NPC	**LRS**			
Rates	NEM Flat	NEM TOU	Revised NEM Flat	Revised NEM TOU
Basic Service Charge	$78.86	$78.86	$78.76	$78.76
Generation Meter*	$8.98	$8.98	$8.96	$8.96
Max Demand Rate ($/kW)	$14.84	$4.11	$14.80	$4.09
Summer On Peak Demand Rate ($/kW)		$28.54		$28.47
Flat kWh Rate ($/kW)	$0.05358		$0.05352	
TOU kWh Rate ($/kWh)				

Summer On		$0.09046		$0.09017
Summer Off		$0.05547		$0.05543
Winter		$0.04727		$0.04727
NPC	**GS**			
Rates	NEM Flat	NEM TOU	Revised NEM Flat	Revised NEM TOU
Basic Service Charge	$35.43	$35.43	$35.39	$35.39
Generation Meter*	$7.57	$7.57	$7.57	$7.56
Max Demand Rate ($/kW)	$15.27	$4.72	$15.23	$4.70
Summer On Peak Demand Rate ($/kW)		$28.27		$28.20
Flat kWh Rate ($/kW)	$0.04960		$0.04954	
TOU kWh Rate ($/kWh)				
Summer On		$0.06653		$0.06615
Summer Off		$0.05049		$0.05044
Winter		$0.04695		$0.04695
*Generation Meter Charge is waived for SolarGenerations customers.				

(See Ex. 98A at 15.) NV Energy states it has three modifications that should be incorporated into SPPC's proposal. Two modifications pertain to the reduction in time to install a generation meter for the D-1 NEM and GS-1 NEM. The third modification reduces the amount of generation costs included in the proposed GS-1NEM demand change. The modified rates are as follows:

SPPC	**D-1**			
Rates	NEM Flat	NEM TOU	Revised NEM Flat	Revised NEM TOU
Basic Service Charge	$24.50	$24.50	$24.50	$24.50
Generation Meter*	$1.12	$1.12	$0.71	$0.71
Max Demand Rate ($/kW)	$8.63	$4.46	$8.63	$4.46
TOU Demand Rate ($/kW)				
Summer On Peak Demand Rate ($/kW)		$14.66		$14.66
Winter On Peak Demand Rate ($/kW)		$1.43		$1.43
Flat kWh Rate ($/kW)	$0.04749		$0.04749	
TOU kWh Rate ($/kWh)				
Summer On		$0.08694		$0.08693
Summer Mid		$0.05934		$0.05933
Summer Off		$0.04302		$0.04302
Winter On		$0.05036		$0.05035
Winter Off		$0.04302		$0.04302
SPPC	**DM-1**			
Rates	NEM Flat	NEM TOU	Revised NEM Flat	Revised NEM TOU
Basic Service Charge	$10.75	$10.75	$10.75	$10.75
Generation Meter*	$1.12	$1.12	$0.71	$0.71
Max Demand Rate ($/kW)	$7.36	$3.70	$7.36	$3.70

TOU Demand Rate ($/kW)				
Summer On Peak Demand Rate ($/kW)		$12.71		$12.71
Winter On Peak Demand Rate ($/kW)		$1.44		$1.44
Flat kWh Rate ($/kW)	$0.04569		$0.04568	
TOU kWh Rate ($/kWh)				
Summer On		$0.10639		$0.10637
Summer Mid		$0.05611		$0.05609
Summer Off		$0.04077		$0.04077
Winter On		$0.04994		$0.04989
Winter Off		$0.04077		$0.04077
SPPC	**GS-1**			
Rates	NEM Flat	NEM TOU	Revised NEM Flat	Revised NEM TOU
Basic Service Charge	$39.00	$39.00	$39.00	$39.00
Generation Meter*	$4.67	$4.67	$4.61	$4.61
Max Demand Rate ($/kW)	$11.07	$5.53	$10.65	$5.53
Summer On Peak Demand Rate ($/kW)		$15.13		$15.13
Winter On Peak Demand Rate ($/kW)		$1.94		$1.94
Flat kWh Rate ($/kW)	$0.04462		$0.04629	
TOU kWh Rate ($/kWh)				
Summer On		$0.08466		$0.08466
Summer Mid		$0.05687		$0.05687
Summer Off		$0.04221		$0.04221
Winter On		$0.04975		$0.04975
Winter Off		$0.04221		$0.04221
*Generation Meter Charge is waived for SolarGenerations customers.				

(See Ex. 93A at 23.)

156. NV Energy states that its proposals take into consideration the principles of rate stability, efficiency, equity, as well as the principles of simplicity, understandability, public acceptability, and feasibility of application. Rates should be changed gradually with minimal unexpected changes seriously adverse to existing ratepayers. It is also important to note that rate stability is not an end in itself and has to be weighed along with other criteria. The NEM1 rates have outlived their usefulness. They were required to jump start the installation of rooftop solar and have successfully done so in the time it took to reach the statutory cap. It is a generally accepted principle that public utility rates are subject to revision if and when they become unreasonable. (Ex. 87A at 2-4.)

157. NV Energy states that the simplest way to develop an equitable pricing structure is to adopt prices that mirror the cost structure of the utility. Demand charges are a good and reasonable fit for NEM ratepayers because NEM ratepayers use existing local grid capacity for both export of unused on-site generation and import of energy from the utility when the on-site generation cannot fully meet demand. The prices that NV Energy charges to the majority of its load have demand charges. The simple fact is that demand charges establish a price that reflects demand-driven costs. (Ex. 101A at 29-33.)

158. NV Energy states that existing rates for NEM1 ratepayers do not have a demand charge that provides the NEM1 ratepayers with an incentive to use capacity efficiently. NEM1 ratepayers do have an energy charge, but that charge does not vary by time of day and provides no incentive to use capacity efficiently. Demand charges should not be equated to fixed costs. Demand charges are largely under the ratepayer's control while fixed charges are not. Both are essential elements in electric rate design because they mirror the structure of utility costs and have been a staple of large commercial and industrial rates for decades. With the advent of AMI, it is now possible to deploy this three-part rate structure to the smaller classes. (Ex. 87A at 4-6; Ex. 93A at 14-16.)

159. NV Energy disagrees with the assertion that NEM ratepayers will not be able to understand the concept of electricity demand. Almost all non-NEM ratepayers have access to their fifteen-minute demand data now, and NEM ratepayers with smart meters will have the same demand data by the end of 2015. To assert that NEM ratepayers can understand consumption-based information but not demand-based information is just not logical—the only difference is the element of time. A host of new technologies and programs are being adopted by ratepayers of all backgrounds: smart thermostats, demand-side management, TOU, and

distributed generation. These new technologies will promote economic efficiency in both a static and dynamic sense. There is clear evidence that ratepayers can understand these advancements and adapt accordingly. The Nevada Dynamic Pricing Trial demonstrated that ratepayers will indeed change their behavior in response to price signals. Knowing that they will respond to price signals, ratepayers have a range of options to lower demand. Understanding that running several appliances at once increases demand and demand costs, ratepayers alter their behavior and spread out those loads. Demand can also be explained easily using the wattage of light bulbs as an example. Ratepayers are smart, capable, and willing to participate in a market that is based on cost causation and fairness. The fact that a ratepayer has decided to install rooftop solar is one indication of that ratepayer's ability to understand energy use as well as the concept of demand. NV Energy plans to educate NEM ratepayers on demand, as well. Further, the notion that all large commercial and industrial ratepayers have energy managers to help manage demand is not true—many small businesses fall under these classes and do not represent large organizations with dedicated energy managers. Demand is simply energy consumption with the additional element of time. (Ex. 85A at 4-10, Ex. 87A at 8-17; Ex. 99A at 76-77; Ex. 101A at 33-35.)

160. NV Energy states that demand charges are not unavoidable. Instead, demand charges signal the cost of providing service by the electric utility and will provide information necessary to allow NEM ratepayers to determine their generation and consumption patterns. Ratepayers can make informed decisions about how much power to consume and at what time. Whether a ratepayer reduces demand in response to a demand charge is a secondary benefit. For instance, demand charges can influence orientation of rooftop solar systems based on when the NEM ratepayer needs the power most (earlier or later in the day). (Ex. 85A at 4-6; Ex. 87A at 9-

11.)

161. NV Energy states that demand charges do not prevent ratepayers from realizing the benefits of NEM installations. By way of example, over 500 ratepayers decided to install NEM systems through the SolarGenerations program, even though these ratepayers are already billed under a three-part rate structure that includes a demand charge. (Ex. 85A at 3.)

162. NV Energy states that modeling ratepayer savings from rooftop solar under a demand charge structure is not too complex for the solar sales process. Current ratepayers considering adding a NEM system can download their fifteen-minute kWh data from the MyAccount web portal, then search their data for the times and values that are the highest. To determine their peak demand, ratepayers simply multiply their highest-value fifteen-minute period by four. (Ex. 99A at 85-86.)

163. NV Energy states that SNHBA's contention that demand charges are too complex to explain and that they discourage ratepayers from buying new solar homes overlooks the fact that buying a new home is a complex interaction that requires mastery of a number of complicated topics such as financing, building materials, design, number of stories, and so on. Similarly, it is hard to imagine that solar ratepayers, who are already familiar with the concepts of capacity (the size of their rooftop solar panels is expressed in kW) are unable or uninterested in investing the relatively small amount of time needed to understand the proposed new rate. The examples of declining solar home sales arise not because of the proposed new NEM rate but because of uncertainty over the future of the NEM rate and the federal investment tax credit. Further, delaying NEM rate changes to the next general rate case will only prolong this uncertainty. (Ex. 87A at 19-20.)

164. NV Energy disagrees with BCP's proposal that a demand charge based on a 60-

minute interval is more appropriate than one based on a fifteen-minute interval. First, BCP is incorrect that residential ratepayers are not coincident with peak loads. Residential air conditioning loads at NPC largely drive the higher-use summer peak season. Further, the fifteen-minute duration is consistent with the duration currently used for the larger commercial classes that include demand charges. The smaller duration will more appropriately reflect the demand that a NEM ratepayer places on the system within a smaller window and will more appropriately reflect the size of facilities that have been built to meet the maximum demands of the ratepayer. (Ex. 93A at 18-19.)

165. NV Energy agrees that TOU rates are an improvement over the existing annual flat-rate in providing price signals that better reflect the variations in costs across the year. However, TOU rates convey an average demand across an entire TOU period and do not reflect the maximum demands that a ratepayer may place on the system during the TOU period. Intermittent and short duration spikes in a NEM ratepayer's load will not significantly affect a NEM ratepayer's energy charges or recover the capacity costs associated with these spikes. NV Energy is obligated to instantaneously meet the maximum demand of the individual ratepayers, thus it is reasonable to recover distribution demand costs based on maximum demand. If these capacity costs are recovered entirely through a kWh energy charge, then higher-than-average-load-factor ratepayers will subsidize lower-than-average-load-factor ratepayers within a class. (Ex. 93A at 12-13.)

166. NV Energy states that if the Commission opts for Staff's proposed rate structure, it should include the recovery of 100 percent of transmission demand and 62 percent of generation demand costs, in addition to Staff's proposed recovery of all distribution costs in the basic service charge. Otherwise, there will still be a cost shift because the current BTGR

volumetric rate recovers 100 percent of transmission and generation demand costs, which are not entirely avoided from the NEM generation. Further, NV Energy states that it believes that utilizing the MCSS developed for full-requirements ratepayers does not accurately reflect the unique cost characteristics of the partial-requirements NEM2 classes. This was actually explicitly noted in SB 374, "[t]he charges included pursuant to this subsection must adequately reflect the marginal costs of providing service to customer-generators." Because of this concern, it is appropriate to use the MCSS and rate designs filed by NV Energy in this Docket versus using those that were last approved by the Commission as proposed by Staff. The table below provides a comparison of Staff's proposed rates, modified Staff rates using the MCSS from Docket Nos. 13-06002 (SPPC) and 14-05004 (NPC) with recovery of 100 percent of transmission demand and 62 percent of generation demand costs, and modified Staff rates using the MCSS in this proceeding with recovery of 100 perception transmission demand and 62 percent of generation demand costs using the NEM MCSS:

SPPC	Staff's Proposed Rates		Modified Staff Rates Using MCSS in 13-06002		Modified Staff Rates Using MCSS in 15-07042	
Class	BSC	kWh BTGR	BSC	kWh BTGR	BSC	kWh BTGR
D-1	$28.36	$0.04063	$48.44	$0.01413	$47.00	$0.02765
DM-1	$13.08	$0.03628	$23.37	$0.01351	$20.50	$0.02646
GS-1	$46.20	$0.03308	$74.18	$0.01113	$154.50	$0.00751

NPC	Staff's Proposed Rates		Modified Staff Rates Using MCSS in 14-05004		Modified Staff Rates Using MCSS in 15-07042	
Class	BSC	kWh BTGR	BSC	kWh BTGR	BSC	kWh BTGR
RS	$33.31	$0.05123	$86.48	$0.00800	$87.78	$0.00816
RM	$16.24	$0.05103	$41.50	$0.01537	$42.94	$0.00998
LRS	$238.32	$0.04971	$689.63	$0.01372	$259.29	$0.00707
GS	$31.04	$0.02175	$47.50	$0.00267	$140.55	$0.00255

(Ex. 93A at 19-20; Ex. 98A at 9-11, 77-78).

167. NV Energy addresses concerns about the banking mechanism and revenue recovery referenced by Vote Solar and Staff. The NEM banking revenue shortfall included in these Applications is an illustrative example of how NV Energy proposes to recover the cost of banking. If the NEM commodity rates were designed using delivered kWh net of excess generated (banked) energy, the commodity rates would be higher and the allocated revenue requirement would be collected appropriately. However, as NEM rates were developed including banked kWh, a difference will exist. (Ex. 98 at 6-8; Ex. 98A at 2-8; Tr. at 1031.)

168. NV Energy states that the buy/sell arrangement for energy proposed by Staff has certain positive attributes. First, the arrangement has the potential to eliminate the very type of cost shifting that SB 374 was designed to address. Because the ratepayer purchases all of the ratepayer's energy requirements from NV Energy, cost responsibility is not shifted to other ratepayers, even when a less-efficient, two-part pricing structure is used. Second, the arrangement has the benefit of efficiently and transparently valuing the energy and any other attributes produced by the NEM systems. The arrangement avoids conflating two separate and distinct transactions: (1) the sale of energy services by NV Energy to NEM ratepayers, and (2) the sale of energy and other attributes by the NEM ratepayers to NV Energy. However, it should be noted that any proposal to pay for excess energy may be prohibited. Pursuant to NRS 704.775(2)(c)(1), the customer-generator is not eligible for cash compensation for excess energy. (Ex. 98A at 78-80; Ex. 101A at 37-38.)

169. NV Energy states that it does not support the shadow billing proposed by Vote Solar. There would be nothing to learn from such shadow prices because behavioral changes cannot be observed without true price signals to which a NEM ratepayer can respond. Further, NV Energy has identified numerous methodological problems with the shadow prices developed

by Vote Solar—shadow prices are not reflective of marginal cost. (Ex. 99A at 73-76.)

170. NV Energy disagrees with TASC's position that bill savings must offset the cost of the rooftop solar system. Instead, rates should be set to reflect costs and avoid unreasonable shifting of costs to other ratepayers. NV Energy reviewed a sampling of contracts NEM1 ratepayers have with rooftop solar providers that show the current NEM1 ratepayers are not seeing monthly savings today, considering the NEM1 bill plus the cost of rooftop solar. Thus, it appears that whatever utility bill savings are expected to be realized accrue to the solar vendor, not the NEM ratepayer. (Ex. 99A at 88-89.)

171. NV Energy states that SB 374 was designed to reduce or eliminate the subsidy for NEM provided by the piloting program that began in 1997. NV Energy provides nearly 20 years of legislative history in support of this conclusion. Also, independent analysis conducted by E3, Lawrence Berkeley National Laboratory, and the Massachusetts Institute of Technology support the conclusion that NEM increases utility rates and shifts costs to non-participating ratepayers. The obvious solution is to redesign the pricing structure for ratepayers who choose to become partial-requirements NEM ratepayers so that fixed and demand costs are removed from volumetric charges. Instead, these costs should be reflected in fixed and demand prices, just as NV Energy has proposed. (Ex. 101A at 18-25.)

172. NV Energy states that the Commission should reject proposals to grandfather NEM2 ratepayers. Placing NEM2 ratepayers under the umbrella of the NEM1 rate structure would increase, rather than decrease, the existing cost shift that SB 374 was meant to address. The Commission should not grandfather NEM2 ratepayers to protect the rooftop solar industry from the consequences of poor contracting decisions. (Ex. 101A at 35-36.)

173. NV Energy states that the Commission should weigh Staff's proposal to not

grandfather any NEM ratepayers under the existing rate structure. Staff's proposal reduces the cost of administering two separate schedules for similarly situated, partial-requirements NEM ratepayers. (Ex. 101A at 36.)

174. NV Energy states that almost all of WCSD's projects are located at facilities billed under an existing three-part pricing structure that already includes a demand charge and thus are not the subject of this proceeding. Further, existing NEM1 rates are not necessary to ensure that the NEM systems installed at WCSD sites provide the appropriate payback. Since 2005, WCSD has installed 36 solar and wind systems through Nevada's incentives programs and received $17.5 million in incentives for these projects. For 32 of 36 projects, NV Energy has information demonstrating that the incentives covered 88.6 percent of the total system costs. In addition, these systems have resulted in energy savings of at least $1,338,787 through October 2015. WCSD is on pace to save approximately $365,000 annually going forward if no changes are made to the NEM1 rates. (Ex. 85A at 2-4.)

BCP Supplemental Position

175. BCP states that the economic payback for NPC's average residential NEM1 ratepayer based on the old NEM rates was approximately 18 years. There is no economic payback for a similar ratepayer under the new NEM rates. (Ex. 119A at 2, 3-5.)

176. BCP recommends that the Commission grandfather all NEM1 ratepayers that meet the definition of paragraph (a) of subsection 1 of Section 2.95 of SB 374 for a period of 20 years from the date of interconnection. Any NEM ratepayers who complete application after the 235 MW threshold is reached should have to abide by the revised NEM tariff rate structure. NEM1 ratepayers who made substantial investments with their own money, even after accounting for tax credits and SolarGenerations program rebates, should be given an opportunity

to recover their investments. (Ex. 119A at 2, 14-17.)

177. BCP states that a 20-year period is appropriate for three reasons. First, NEM ratepayers should be given an opportunity to recover the costs of their investment in a NEM system, which takes on average 18 years. Second, NV Energy issued a news release proposing to allow NEM1 ratepayers to remain on the old NEM rates for as long as 20 years. Third, a 20-year period from the date of interconnection allows all NEM1 ratepayers the same period of time to recover their investments. (Ex. 119A at 18.)

178. BCP states that the legacy NEM rate structure should stay with the customer and premise. The customer who made that investment should be able to recover the investment on the premise where the solar PV was installed before the 235 MW threshold was reached. If a NEM system fails and the customer replaces the system for no more kilowatts than the original solar PV generator, then the customer should be able to keep the rate structure for the period of time remaining in the grandfathering clause. Any additional panels should be subject to the NEM2 rate structure given that they were added after the 235 MW threshold was reached. (Ex. 119A at 17.)

179. BCP states that the grandfathering of NEM1 ratepayers provides a comparable or lower price per kilowatt hour for energy from the customer-generators than the price per kilowatt hour for recent large-scale solar PV and other renewable energy contracts that are passed through to ratepayers. The carry-forward rate under the old NEM rates was $0.11289 for an NPC residential NEM1 ratepayer and $0.08829 for an SPPC residential NEM1 ratepayer. For the three large-scale solar PV contracts placed into service from 2012 to 2014, the average price passed-through to NPC's ratepayers was approximately $0.135 (Silver State Solar Power North), $0.112 (Spectrum Nevada Solar), and $0.117 (Mountain View Solar). (Ex. 119A at 2-3, 18-23.)

180. BCP states that any subsidies to grandfather all NEM1 ratepayers under the old NEM rates are less than NV Energy's net annual expense for the One Nevada Transmission Line ("ON Line"). The estimated annual expense for NPC's ratepayers for the ON Line in order to transfer renewable energy from north-to-south or south-to-north is $44.2 million. The subsidy for NEM1 ratepayers is only $16 million annually. (Ex. 119A at 3, 23-25.)

181. BCP states that grandfathering NEM1 ratepayers is consistent with the energy policies to promote renewable energy as codified in various Nevada Revised Statutes from 1997 until the present. In 1997, the Nevada Legislature passed SB 255 to provide for NEM in Nevada. The original statute limited the size of NEM systems to no more than 10 kilowatts. In 2003, the Nevada Legislature passed AB 431 to increase the allowable size of NEM systems to no more than 30 kilowatts. In 2005, the Nevada Legislature passed AB 236 to increase the allowable size of NEM systems to no more than 150 kilowatts. Finally in 2007, the Nevada Legislature passed AB 178 to increase the allowable size to no more than 1,000 kilowatts. In 2001, the Nevada Legislature passed SB 372 to establish a renewable portfolio standard ("RPS") in Nevada. The RPS has been amended several times since 2001 and the current RPS requirement is 25 percent of energy sales by 2025. In 2003 the Nevada Legislature passed AB 296 to provide a 2.4 multiplier for calculating RPS credits for certain solar PV systems, recognizing that rooftop solar PV was more expensive on a per kilowatt hour basis than other forms of renewable energy. In 2013, the Nevada Legislature passed SB 252 to eliminate the solar PV multiplier for systems installed after December 31, 2015. (Ex. 119A at 3, 25-27.)

182. BCP states that if NEM1 systems are not grandfathered, the solar PV industry will view Nevada as a hostile regulatory environment and any future development of the rooftop solar PV industry in Nevada will cease, which is contrary to the legislative policies expressed in NRS

704.766 and 701B.190. (Ex. 119A at 27.)

183. BCP states that the Commission should explore some of the other options in Section 2.3 of SB 374 to provide for the continued development of distributed solar PV in Nevada. If NEM2 systems were limited to an allowable size of no more than 10 kilowatts, like originally provided for in SB 255, and an annual MW cap were established for the total net capacity that could be reached, then the development of the distributed solar PV industry in Nevada could continue as long as the billing structure was consistent with NRS 704.775. (Ex. 119A at 28-29.)

184. BCP states that it is unaware of any education outreach it has provided to solar customers regarding the NEM changes pursuant to SB 374. (Tr. at 1443-1445.)

GBSC Supplemental Position

185. GBSC recommends that the NEM ratepayers remain on the existing legacy rate schedule. This should include all NEM ratepayers who submitted a reservation prior to the approval of new rates on December 31, 2015. Each of the NEM systems was designed to conform to this rate structure, and any deviation from it will create endless conflicts. This serves to protect the investments made by NEM ratepayers and investments made by the industry in developing projects prior to the decision on the new rates. (Ex. 116A at 1-2.)

186. GBSC recommends that the NEM ratepayers be grandfathered indefinitely, until such time as the owner of the parcel chooses to take service under another schedule. NEM ratepayers must be allowed the opportunity to fully recover all return on investments ("ROI"). Recovery of an accurately calculated ROI is a complicated formula that GBSC has seen no evidence that any party nor this Commission is prepared to calculate. This inability to quantify is exacerbated by the fact that there are an estimated 17,000 separate investments requiring full

recovery of ROI. Also, while the expected minimum production of a solar system is a figure that can be quantified, the anticipated production is far more abstract. So, a ratepayers anticipated recovery of an investment could easily stretch out beyond 40 years. Therefore, the only feasible and reasonable method to allow recovery of the investment is to permit those investments to fully mature. Any impositions of time limits, or limiting of future alterations to the NEM system will only serve to discriminate and unjustly penalize at least some portion of the NEM1 ratepayer class. GBSC also acknowledges that some NEM1 ratepayers only installed their NEM systems for environmental and societal reasons. (Ex. 116A at 2.)

187. GBSC states that if there is attrition under the 235 MW threshold, additional systems should be grandfathered into the group. Grandfathering appropriately serves to acknowledge the investments of those ratepayers and the industry professionals who have incurred significant expense to develop those projects. (Ex. 116A at 2.)

188. GBSC states that grandfathering could restore a measurable amount of consumer confidence in the market. Also, a failure to grandfather will serve to reduce the existing quantity of operational DG systems. Grandfathering would preserve the economic benefits of the systems included and respects the terms that the NEM ratepayer accepted when he/she chose to invest in the NEM system. (Ex. 116A at 3-4.)

189. GBSC states that ratepayers who realize bill savings from DG inevitably spend a significant portion of those savings in the local community. GBSC makes no presumptions on how the various companies structure or manage their assets regarding leased DG nor on those models' effect on the economy. The old NEM rates clearly offered large benefits for local economies, and those benefits have been erased by the new NEM rates. (Ex. 116A at 3.)

190. GBSC states that none of its members provided any information about SB 374 to its solar customers. (Tr. at 1403.)

NV Energy Supplemental Position

191. NV Energy recommends that the Commission establish September 10, 2015, as the point of demarcation for managing change. [28] This effectively is the date on which installed capacity plus capacity of applications in the pipeline settled at 235MW. Initially the installed capacity plus the capacity of applications in the pipeline received reach 235MW on August 20, 2015. However, NV Energy managed the application queue. As attrition occurred, NV Energy notified applicants that their application fell under the 235 MW mark referenced in SB 374. On December 15, 2015, NV Energy notified an applicant who submitted a completed application on September 10, 2015, that his/her application now fell within the 235 MW threshold. Thus September 10, 2015, is the last day on which installed capacity plus the capacity of applications in the pipeline was at or below 235 MW. To the best of NV Energy's knowledge, every applicant who submitted completed application after September 10, 2015, received notification that the ratepayer did not qualify for NEM1 status. (Ex. 103A at 41-42.)

192. NV Energy provides the following table of the number of installed systems and applications in the pipeline on the relevant dates:

	NPC			SPPC			NV Energy Total
	Installed	Pipeline	Total	Installed	Pipeline	Total	
10-Sep-15	10,758	13,388	24,146	1,868	929	2,797	26,943
Residential (Para. 88, fn. 12)			23,422			2,461	25,883
Minimum Subsidy (Para. 88)			$14,591,669			$1,159,301	$15,750,970
23-Dec-15	15,075	13,529	28,604	2,545	993	3,447	32,051
Single Family (Para. 88, fn. 12)			27,746			3,033	30,779
Subsidy per unit (Para. 88)	@ $623 per unit		$17,285,683	@$471 per unit		$1,428,713	$18,714,396
Incremental			$2,694,014			$269,412	$2,963,426

[28] NV Energy states that "grandfathering" is an ambiguous term that might mean different things to different individuals and, therefore, is best understood within the context of managing change associated from one pricing structure and regime (that yields a cost shift) to another pricing structure and regime (that does not include a cost shift). NV Energy prefers to use the term "change management" to describe the debate. (Ex. 103A at 10-11.)

NV Energy states that the cost shift from NEM ratepayers to non-NEM ratepayers is approximately $623 and $471 for each single family residential NEM ratepayers within NPC's and SPPC's service territory, respectively. Using those amounts, the annual subsidy is estimated to be $15.75 million if September 10, 2015, is the point of demarcation and $18.71 million annually if December 23, 2015, is the point of demarcation. The calculations only reflect the cost shifting associated with single family residential installations. Applications and installations in the general service, large single-family residential and multi-family residential classes are not reflected in the calculations. While the Commission correctly found that 97 percent of installations within NPC's service territory and 88 percent of installations within SPPC's service territory were single family installations at the time of the filing, more than 99 percent of applications in the pipeline are for single family residential applications. So, these calculations are a reasonable estimate of the total cost shift from NEM ratepayers to non-NEM ratepayers in the residential and small commercial service classes. (Ex. 103A at 43-45.)

193. NV Energy states that a laddering process reflects the principle of "gradualism." Gradualism is the concept used by utility regulatory commissions to manage change associated with moving utility prices to reflect new or changing rate structures of costs of service. Change management options are spread across a spectrum, from an immediate single step change from one pricing structure and regime to a significantly delayed implementation followed by an immediate change. Staff's proposal is at one end of the spectrum, and TASC's proposal is at the other end. (Ex. 103A at 45-49.)

194. NV Energy states that the Commission should consider seven alternatives for reducing and eventually eliminating the unreasonable cost shift created by the pre-SB 374 regime. The Commission should then adopt the alternative that balances the interests of NEM

and non-NEM ratepayers. The primary consideration in this balancing test should be the magnitude of the cost shift that results from the change management solution selected by the Commission. (Ex. 103A at 49-50.)

195. NV Energy recommends that the Commission evaluate and choose one of seven alternatives for eliminating the substantial subsidy (i.e. cost shift) created by the old NEM rules. The cost shifting is the product of a 1997 pilot program that required NV Energy to provide service to NEM ratepayers with a specific rate structure designed to encourage what was then a new technology and a nascent industry. NV Energy proposes to use September 10, 2015, as the point of demarcation for NEM ratepayers who would qualify for the change management strategy adopted by the Commission. NV Energy. This represents the last date upon which a NEM ratepayer was included under the 235 MW cap established by SB 374. The seven options for managing change described below are:

Option 1: gradual changes over 4 years,
Option 2: gradual changes over 8 years,
Option 3: gradual changes over 12 years,
Option 4: gradual changes over 16 years,
Option 5: gradual changes over 20 years,
Option 6: delay a course correction for 10 years, or
Option 7: delay a course correction for 20 years.

Under Options 1-5, NEM ratepayers would see four gradual changes of varying lengths over the transition period. Under Options 6-7, NEM ratepayers would only see one step change, and that change would be delayed for the length of the transition period. In evaluating each of these options, the Commission should consider the cumulative cost shifting associated with each option when it balances the interests of all utility ratepayers. The following is the total costs that would be shifted to non-NEM ratepayers using a point of demarcation of September 10, 2015:

Option 1: ~$27 million
Option 2: ~$54 million

Option 3: ~$81 million
Option 4: ~$109 million
Option 5: ~$136 million
Option 6: ~$158 million
Option 7: ~$315 million

(Ex. 103A at 5-6, 50.)

196. NV Energy states that the 16 and 20-year ladders (Options 4 and 5) have cumulative cost shifts that are lower than the 10-year delay in the step change (Option 6). Also, the 10 and 20-year delays of a step change (Options 6 and 7) do nothing to gradually effect a change and do not avoid, reduce or eliminate the current cost shift for the entire period of the delay; these two options provide little value if the Commission is concerned with allowing NEM ratepayers time to adjust to incremental different price signals. (Ex. 103A at 53.)

197. NV Energy states that the Commission could also consider regulatory precedent and/or the magnitude of the subsidies expressly adopted by the Nevada Legislature for certain specific purposes when selecting a process for reducing and eliminating the unreasonable cost shift that occurs under the legacy NEM rate structure. First, in 1982 SPPC acquired electrical service connections from CP National, including residential customers in the Elko area. In 1983 the Commission provided for a seven-year transition period (actually lasting nearly ten years), providing for separate service rates for former CP National customers. Second, in 2013, the Legislature enacted the economic development rider (NRS 704.7871 to 704.7882) establishing a subsidy in the form of a rate reduction to certain qualifying customers. The program is capped at 50 MW, which equates to approximately $31 million over the discount period statewide. The Commission can rely on these regulatory policies as compass points as it considers and selects a change management process for first reducing and then eliminating the cost shifting that occurs under the legacy NEM rate structure. (Ex. 103A at 54-55.)

198. NV Energy states that Options 2 and 3 are more closely aligned with the express economic development rider subsidy and the gradual transition for Elko residential customers to system-wide rates. Options 4 and 5 place greater weight on the length of the total transition period and less weight on cost shifting. (Ex. 103A at 57.)

199. NV Energy states that Options 6 and 7 would step back on the ladder and remove any progress made in reducing the total annual costs shifted to non-NEM ratepayers. These two options do not produce incremental changes. Instead, the options simply delay the necessary course correction identified by the Commission. If the Commission selects one of these alternatives, NV Energy recommends that the Commission establish (as it already has) separate classes for NEM ratepayers and then perform an interclass rebalancing calculation to reassign the revenue shortfall to all customer classes—the amount of the subsidy is transparently transferred to other network users. There would simply be two separate rate categories within those classes. One rate category would have the same rats as the otherwise applicable full-requirements class, while the other rate category would be assessed cost-based rates and the value-based excess energy credit set by the Commission. (Ex. 103A at 57-58.)

200. NV Energy states that beginning in July 2015, every ratepayer who submitted a completed application for NEM service received an electronic mail from NV Energy that contained information regarding SB 374. In particular, the message stated:

> . . . we are not able to guaranteed that your system will be eligible for net metering under the current rules and at the current net metering rates. Given the Public Utilities Commission of Nevada is in the process of adopting new rules and rates, we are also unable to provide you with an estimate of the rate that may be applicable to energy usage at your premise or energy produced by your new rooftop solar system. While we recognize this situation leaves open many questions and is not desirable for anyone involved, we felt it important for you as our valued customer to be aware of the current status of the rules and rates applicable to your new rooftop solar system.

From August 3, 2015, though August 20, 2015, when the 235 MW threshold was met, every ratepayer who submitted a completed application for NEM service during this period received an electronic mail from NV Energy that contained information regarding SB 374. In particular, the message stated:

> Based on the time your application was submitted, your project is subject to interim net metering rules and rates. The Public Utilities Commission of Nevada is scheduled to establish new rules and rates on or before December 31, 2015. The new rules and rates could differ from the interim rules and rates and the new rules and rates may be applied to you.

From August 20, 2015, through December 24, 2015, after the 235 MW threshold was met and until the Commission's Order on the new NEM rates was issued, every ratepayer who submitted a completed application for NEM service during this period received an electronic mail from NV Energy that contained information regarding SB 374. In particular, the message stated:

> Based on the time of your application was submitted, your project is subject to new net metering rules and rates. The Public Utilities Commission of Nevada is scheduled to establish new rules and rates before December 31, 2015. The new rules and rates could differ from those rules and rates previously applicable to a net metering system.

Notifications through U.S. mail with identical information referenced above were sent from August 20, 2015, through December 24, 2015. (Ex. 103A at 15-18.)

201. NV Energy states that NEM ratepayers and the system owner (where the NEM ratepayers is not the system owner) are required to execute a standard form letter agreement addressing their interconnection agreement. Since 2004, each iteration of the interconnection agreement includes the governing authority (Section 9), which states that the NEM tariffs may be amended by the Commission at any time. From 2004-2008, Section 9 stated:

> Utility's distribution tariffs may be amended by the PUCN at any time.

From 2009-present, Section 9 stated:

> This Agreement shall be governed and construed under the laws of the State of Nevada as they may be amended or superseded from time to time. The Public Utilities Commission of Nevada . . . or the Utility may amend its tariffs upon Commission approval, which amendments are subject to public noticing requirements.

(Ex. 103A at 19-21.)

202. NV Energy recommends that the Commission consider the NEM1 system as being tied to an address, a premise, or an account. (Hearing Tr. August 21, 2015 at 71.) This is consistent with the Commission's finding in Docket No. 02-06041, where Kerr-McGee was allowed to sell its property and the entity purchasing the property was allowed to assume the benefits of the special contract for power from the Hoover project. Similarly, this would allow a NEM1 ratepayer to sell a property, and then the individual who purchases that property will step into the shoes of the NEM1 ratepayer and continue to receive NEM service under the existing rates. (Ex. 103A at 21-23.)

203. NV Energy recommends that facilities that fail or fall into disuse should not be back-filled or replenished. As time passes, facilities within the 235 MW threshold that fall out of use should be eliminated from the NEM1 designation. (Ex. 103A at 23.)

204. NV Energy recommends that if a NEM1 facility is expanded, the entire facility should fall under the new NEM rates and tariffs. (Ex. 103A at 23-24.)

205. NV Energy states that approximately 27,500 (or 80.1percent) of all NEM1 installations and applications for NEM service received by NV Energy before December 31, 2015 were completed using incentives paid from the Solar Energy Systems Incentive Program adopted in 2007 (see NRS 701B.190). Both NRS 701B.190 and 704.766 address the pre-SB 374 regime. Under SB 374, the Commission is charged with deciding the extent to which the pre-SB 374 regime will be replaced by the new NEM rates and tariffs. (Ex. 103A at 24-25.)

206. NV Energy states that grandfathering does not encourage solar development, which is a forward-looking concept. NEM 1 ratepayers have already made their decision to purchase or lease a NEM system, or purchase energy from an owner of a distributed renewable generation system through a power purchase agreement ("PPA"). Allowing a specific group of NEM ratepayers to continue to receive service under the pre-SB 374 regime (thereby shifting grid cost responsibility to non-NEM ratepayers), or to gradually transition toward cost-based rates over time does not encourage NEM1 customers to take any action that would impact the future development of solar distributed generation. (Ex. 103A at 25-26.)

207. NV Energy states that grandfathering probably aids in establishing a sustainable and self-sufficient solar renewable energy industry in Nevada. The majority of NEM1 ratepayers have entered into long term contracts, either PPAs or lease agreements, with third-party solar providers. To the extent NEM1 ratepayers do not believe they will obtain the benefit of their contracts with third-party solar providers, those providers can expect payment defaults and lawsuits challenging their underlying agreements. Grandfathering may have the forward-looking impact of forestalling payment defaults and lawsuits from discontent NEM1 ratepayers. (Ex. 103A at 26.)

208. NV Energy states that grandfathering does not encourage future investment in renewable energy resources. Continuing to charge NEM ratepayers prices that do not reflect the cost of the unique services those ratepayers receive does not encourage those ratepayers to take any action that would impact the future investment in renewable energy resources. Grandfathering will extend or perpetuate cost shifts. From a macro-economic perspective, a ratepayers who is subjected to cost shifts will have less ability, and be less likely to invest in renewable resources. Furthermore, perpetuating a cost shift might actually discourage more

economically efficient investments in renewable energy. (Ex. 103A at 27-28.)

209. NV Energy states that grandfathering does not stimulate the economic growth of this State. The stimulation of economic growth is a forward-looking concept. NEM1 ratepayers have already made their decision to install a NEM system and third-party developers have already responded to those decisions. From a macro-economic perspective, if NEM1 ratepayers are able to avoid or delay paying all or a portion of the new NEM rates, they will have more disposable income, and to the extent they spend that disposable income in Nevada, may have a stimulating impact on the Nevada economy; however, this impact may be all or partially offset by the dampening impact that cost shifts have on non-NEM ratepayers, who will reduce their disposable income. Grandfathering does not create disposable income, it transfers disposable income from one customer group to another customer group. (Ex. 103A at 28-29.)

210. NV Energy states that grandfathering may enhance the continued diversification of the energy resources used in this State if it causes NEM1 ratepayers to retain their solar systems longer. (Ex. 103A at 29.)

211. NV Energy states that grandfathering is a change management tool. There are very real and significant difficulties in tying a grandfathering mechanism to either the payback for the cost of a NEM system as recommended by BCP or the length of the NEM ratepayer's contract with its third party solar provider. First, for some ratepayers, the installation of rooftop solar has nothing to do with economics. For these ratepayers, tying a grandfathering mechanism to the terms and conditions of any agreements related to their investment makes no sense. Second, the terms and conditions of the contractual commitments governing rooftop solar installations are extremely variable, accomplished through one of three primary commercial structures: purchase/installs, purchased power agreements, and leases. Even TASC's witness

stated that it is difficult to do a payback period under these approaches. (Tr. at 376.) There is no uniformity in the costs of equipment or installations, the duration of financing agreements, or interest rates or other terms and conditions. Neither NV Energy nor the Commission is privy to or has access to the NEM ratepayers' contemporaneous break-even estimate. (Ex. 103A at 29-34.)

212. NV Energy states that the grandfathered ratepayers are shielded from the new NEM rates and tariffs. The non-NEM ratepayers are harmed when the cost shift continues to grow, which is what occurs as the change management process is extended over a longer period of time. (Ex. 103A at 34-35.)

213. NV Energy states that when SolarCity's PPAs and leases are monetized, through transfers to third-party financing funds, it appears that the monthly payments from SolarCity customers are also transferred to the third-party financing funds. It is unclear who has a controlling interest in the PPAs and leases transferred into these funds. SunRun has established 24 investment funds, which represent financing for an estimated $4.0 billion in value of solar energy systems on a cumulative basis. Both SolarCity and SunRun are in the best positions to identify these funds and whether any proceeds from their customers in Nevada remain in Nevada. (Ex. 103A at 35-38.)

214. NV Energy states that there are potential drawbacks to the installation of rooftop solar systems. Many PPAs and lease agreements remain with the house, potentially hindering sales and refinancing. Such long-term contractual commitments can outlast the customer's roof, the customer's occupancy of the home, or the third-party contractor's business life. As a semi-permanent fixture, there is the potential that the work performed by a solar installer can void a roof warranty or impact roof maintenance. (Ex. 103A at 38.)

215. NV Energy states that there generally has been a drop in the purchase power price for large scale solar projects and rooftop solar projects. Large scale solar has seen a significant drop in price. The first solar contract signed by NV Energy was at $185/MWh (18.5 cents per kilowatt hour) with escalation, while the most recent large-scale solar projects approved by the Commission on September 15, 2015, (Boulder Solar and Switch Station) and on January 25, 2016, (Playa Solar I (First Solar) and Boulder Solar II (Sunpower)) contained the following pricing: Boulder Solar—4.6 cents per kilowatt hour, with no escalation; Switch Station—3.87 cents per kilowatt hour, with 3 percent escalation; Playa Solar I—3.87 cents per kilowatt hour, with 3 percent escalation; and Boulder Solar II—3.99 cents per kilowatt hour, with 3 percent escalation. Meanwhile, the installed cost of rooftop solar generally has been declining but recently began increasing. The installed cost in 2008 was $9.1/watt ($9,100/kilowatt) to $4.9/watt ($4,900/kilowatt) in 2015. (Ex. 103A at 39-41.)

SEIA Supplemental Position

216. SEIA states that grandfathering will encourage the development of solar distributed generation systems in Nevada. In order for consumers to invest in solar distributed generation systems, they must be able to accurately evaluate the costs and benefits of that investment. In order to accurately evaluate that investment, consumers must be able to determine what those costs and benefits of the investment will be over time. If the policies relating to the investment are subject to substantial change over that period, consumers cannot accurately determine whether the investment presents a positive economic benefit, and they will not make the investment. The effective evaluation and continued investment, therefore, requires a reasonable degree of regulatory certainty. (Ex. 114A at 4.)

217. SEIA states that in this case, new NEM rates represent an abrupt and drastic

departure from the legacy NEM rates. The new NEM rates drastically reduce bill savings for NEM ratepayers who in some circumstances have financed or leased their NEM system over a period of time that has not yet come to a close, dictating an entirely different economic outcome than was anticipated at the time those NEM ratepayers evaluated their initial investment. Many of those NEM ratepayers would likely not have made the investment had they been aware of the potential change at the time they invested. Such a change in rates not only undermines the value of those investments, but it reflects a disregard for the regulatory certainty required to incentivize ratepayers to invest in solar distributed generation systems. Failing to grandfather existing NEM customers will signal that the Commission is not concerned with the effect on rate structure changes for existing NEM ratepayers and the impact it has on their initial investment in evaluating proposals to change the operating rules under which those NEM ratepayers take service. (Ex. 114A at 5.)

218. SEIA states that disregard for NEM ratepayers' investment expectations would send a chilling signal to potential solar distributed generation customers going forward because they cannot rely on the rate structure in place at the time of the evaluation of the initial investment. Very few people will invest in NEM systems, and solar installation companies will cease to offer their products and services in Nevada because there will be no demand for the NEM systems. (Ex. 114A at 5-6.)

219. SEIA states that grandfathering existing NEM ratepayers would reflect the Commission's acknowledgement of the fact that NEM ratepayers made their initial investment with certain expectations consistent with the policies in place at the time of the investment and will honor those expectations over the life of the investment. This will ensure that future NEM ratepayers are not deterred from making the investment because of a perceived instability in the

regulatory climate associated with the investment. NEM ratepayers reasonably understood that their rates could change in the same manner as other non-NEM ratepayers, but it is not reasonable to assume that their rate structure could be entirely overhauled, particularly with the export of energy no longer valued at retail rates. (Ex. 114A at 6.)

220. SEIA states that grandfathering affirms a commitment to regulatory certainty. Grandfathering ensures that ratepayers will not be deterred from future investment on account of regulatory uncertainty. For these reasons, grandfathering also aids in establishing a sustainable and self-sufficient solar renewable energy industry along with private investment in renewable energy resources, stimulates the economic growth of Nevada, and enhances the continued diversification of the energy resources in Nevada. (Ex. 114A at 7-11.)

221. SEIA states that the term "renewable energy resources" is limited to NEM systems as that term appears in NRS 704.766(1). NRS 704.766(1) lays out the policy objective with respect to NEM systems specifically. As such, the Legislature appears to have set forth policies to encourage investment in renewable energy resources in the specific form of NEM systems. (Ex. 114A at 9.)

222. SEIA recommends that the Commission grandfather all residential rooftop solar customers with applications for service in before the Commission issued its Order on December 23, 2015, in the interest of regulatory certainty. Each of those customers made an investment decision based on the prior rate structure and therefore had a reasonable expectation that the rate structure in place would continue over the life of their investment. The fact that those customers knew or should have known that this proceeding was pending is irrelevant—the outcome was entirely speculative; no NEM ratepayer or prospective NEM ratepayer knew what rate structure would be imposed on them. A minimum grandfathering period of 20 years represents reasonable

(investment backed) expectations of NEM ratepayers given the average life expectancy of solar panels, as well as NEM lease and financing arrangements. A 20-year period is consistent with a recent decision in California. In Hawaii, grandfathered NEM ratepayers are authorized to take service under the NEM tariff indefinitely. (Ex. 114A at 11-13.)

223. SEIA states that it is a trade association with no consumer education and, therefore, has not provide any information to solar customers regarding NEM changes pursuant to SB 374. (Tr.at 1372.)

Staff Supplemental Position

224. Staff recommends that the NEM rate structure already established by the Commission apply to all NEM ratepayers, including NEM ratepayers who participated in NEM prior to the 235 MW cap under SB 374 being met. First, there was consensus among stakeholders during the 2015 legislative session on the language of SB 374, which plainly provides that the Commission may determine whether grandfathering of NEM1 ratepayers should occur. Second, regulated utilities like NV Energy are generally not allowed to discriminate. The ratemaking principle of horizontal equity supports treating equals (NEM ratepayers) equally. Third, NV Energy used NEM1 ratepayers as the proxy for NEM2 ratepayers for the cost of service study. It is not appropriate to use NEM1 data for NEM2 ratepayers and then not apply those same rates to NEM1 ratepayers. Fourth, the new NEM rates provide a more accurate signal of the value of excess generation to all NEM ratepayers. Providing different price signal to similar ratepayers is illogical and potentially confusing. Fifth, it is not practical to track different generations of customers, especially when considering factors like whether the grandfathered NEM rates would stay with the customer or account and any additional costs to track these differences should be allocated to the NEM classes. Finally, TASC has filed suit

claiming anticompetitive causes of actions against Salt River Project for differential treatment of NEM ratepayers, and has not explained how the Commission's potential differential treatment of NEM ratepayers would not be used by TASC or its members or others as a basis to attack NV Energy and/or the Commission for alleged anticompetitive efforts. (Ex. 121A at 19-20.)

225. Staff states that the Commission could consider a laddering period so that there are slower incremental approaches to cost-based NEM rates. The Commission could establish a transitional period of 10 years and correspondingly impose annual 10-percent incremental steps toward cost-based NEM rates. The BCP previously suggested an 8-10-year grandfathering period for NEM1 ratepayers, which equates to a total subsidy of at least $128-160 million. By utilizing the longer duration proposed by BCP in combination with the laddering or partial/incremental grandfathering approach, the Commission would significantly decrease the cost-shift from NEM1 ratepayers. Another option would be to sync the grandfathering with the SolarGenerations program, which is set to expire on December 31, 2025. While the NRS 701B program is clearly a different program from NEM, the Commission could logically sync the timeframe for incentives to be paid to assist in jump-starting the industry with the continuation of non-cost-based rates that also jump-started the industry. A further option could be to compare the time allowed for NV Energy to adjust to changes as a result of a customer departure pursuant to NRS Chapter 704B. The Commission could consider giving NEM1 ratepayers a similar amount of time (6 years) to modify their behavior and investments. Finally, the Commission could choose a grandfathering period to match the payback data presented in this case ranging between 5, 8, 10, 16, or 17 years. (Ex. 121A at 20-22.)

226. Staff states that it uses the term "grandfather" to apply to ratepayers who applied for NEM up to the 235 MW cap (which are referred to as NEM1 ratepayers) and not to the

ratepayers whose applications/installations would exceed the 235 MW cap (which are referred to as NEM2 ratepayers). Subsection 2.3(3) of SB 374 plainly establishes the cutoff for any potential grandfathered NEM ratepayers as NEM ratepayers who submitted completed applications under the 235 MW threshold. The 235 MW threshold is echoed in subsection 2.95(1)(a) of SB 374 to establish the timeframe for the shift to cost-based rates for NEM ratepayers. Nothing in SB 374 points to a different cutoff. (Ex. 121A at 1-3.)

227. Staff recommends that if the Commission decides to grandfather certain NEM ratepayers, those ratepayers should be tracked in a rate class separate from both non-NEM ratepayers and NEM ratepayers who are not grandfathered. If effect, that would create multiple NEM classes: one for NEM1 grandfathered ratepayers, which would be closed to new applicants, a second NEM class for NEM2 ratepayers, and a third (or subset of NEM2) for NEM2 ratepayers who choose the TOU option. Staff is not recommending that the Commission consider merging the NEM1 ratepayers back in with non-NEM ratepayers. (Ex. 121A at 2-3.)

228. Staff presents publicly available information from the parties' and other public websites regarding whether ratepayers were informed that rates may change as a result of the legislative mandate in Section 2.3(3) of SB 374. First, the Sample Interconnection Agreement for Net Metering of Renewable Energy Generating Facilities from NV Energy's website contains the following regarding governing authority:

> This Agreement shall be governed and construed under the laws of the State of Nevada as they may be amended or superseded from time to time. The Public Utilities Commission of Nevada ("Commission") or the Utility may amend its tariffs upon Commission approval, which amendments are subject to public noticing requirements.

The Sample Interconnection Agreement provided by NV Energy accurately represents to any NEM ratepayers that tariffs and laws could change. Bombard, a party to these proceedings, provides a "news" tab on its website that appears to be updated from time-to-time with information regarding the passage of SB 374 and the Commission's rulings in these Dockets. Staff did not find a discussion of subsection 2.3(3) of SB 374 on the websites for SolarCity (former member of TASC), SunRun (member of TASC), or SUNworks (member of GBSC). Dockets) website. Thus, based on the publicly available website information provided by NEM installation/financing companies that are parties to these proceedings, only Bombard acknowledges SB 374 and potential changes to NEM rates. However, NV Energy's Sample Interconnection Agreement plainly states that Nevada laws and applicable tariffs are subject to change, and all NEM ratepayers must execute an Interconnection Agreement in order to be allowed to connect to NV Energy's distribution grid. (Ex. 121A at 3-6.)

229. Staff states that grandfathering possibly encourages the development of solar distributed systems in Nevada. Grandfathering would not for those who have already installed the NEM systems, but grandfathering would encourage the completion of those system that have yet to be built. This would be a short-term boost and Staff does not have any data to show whether or not grandfathering NEM1 ratepayers will bring businesses back that are no longer in business. (Ex. 121A at 6-7.)

230. Staff states that grandfathering is not likely to aid in establishing a sustainable and self-sufficient solar renewable energy industry in Nevada. It is possible that a business could find a sustainable business model dealing primarily in maintenance and possibly panel additions. However, grandfathering does not make the overall industry more sustainable or self-sufficient. Instead, the estimated cost-shift from what appears to be less-affluent non-NEM ratepayers to more affluent NEM ratepayers is eye-opening: over $16 million per year and totaling over $400 million using a 25-year NEM system life expectancy for all NEM1 ratepayers. Nevada

legislators prophetically explained during the discussion on SB 374 that solar installation/financing companies' business models would need to change as cost shifts or subsidies are reduced. Senator Kelvin Atkinson stated in relevant part:

> When these things [subsidies] go away, you do have to change your business model somewhat. If you have made billions of dollars the last few years, you should be able to afford to do that. While we will have some people disagree with that, that is exactly what we believe. Some of these industries will have to change their business model to fit what Nevada is going to be doing.

(Minutes of May 20, 2015 Meeting of the Assembly Committee on Commerce and Labor, at 50.) It is important to note that the combination of the Federal Income Tax Credit ("FITC"), SolarGenerations program incentives, and prior non-cost-based NEM rates jump-started the NEM portion of the solar industry in this State. Those other two financial incentives (the FITC was recently extended and SolarGenerations program incentives funds remain though dwindling) continue and may continue to support sustainable NEM in Nevada in the future. (Ex. 121A at 7-8.)

231. Staff states that most NEM1 ratepayers have already made the investment, so grandfathering them is not likely to encourage further private investment in small-scale systems. Grandfathering may encourage limited private investment in the short-term for ratepayers who applied for NEM under the 235 MW threshold but who have not actually installed or energized their NEM system. (Ex. 121A at 8.)

232. Staff states that the term "renewable energy resources" as used in the declaration of the legislative purpose of NEM, NRS 704.766(1), is not separately defined in the NEM statutes and is certainly not limited to NEM systems. The definition of "renewable energy" in the NEM statutes incorporates by reference RPS statutes' definition of "renewable energy," NRS 704.7811. In the RPS statutes (specifically, NRS 704.7811, 704.7815, and 704.7823),

"renewable energy" is defined to include but not be limited to biomass, geothermal energy, and waterpower; "renewable energy systems" are defined to include NEMs but extend beyond them to even cover "qualified recovery process" facilities (except tires). If the Legislature had wished to declare it is the purpose of the NEM statutes to be focused solely on NEM, the Legislature could have plainly stated as much. Instead, the Legislature appears to have recognized that NEM is just one piece of the larger renewable energy resources puzzle. Cost-based rates that may increase costs for NEM systems relative to other renewable technologies will encourage private investment in other renewable technologies such as large-scale solar PV and storage technologies which will stimulate the economic growth of Nevada and enhance the continued diversification of the energy resources used in Nevada. While Staff has heard arguments that changing the NEM rates and structure has a chilling effect on companies that choose to do business in Nevada, the Commission very recently approved three solar PPAs that add 129 MW of solar generation capacity in Nevada without negative impacts to ratepayers' rates. Therefore, the Commission appears to have been consistent in its pursuit of least-cost renewable energy options for ratepayers, and larger scale solar developers do not appear to have been chilled from developing renewable energy resources in Nevada. (Ex. 121A at 8-9.)

233. Staff states that grandfathering would have no significant effect on the economic growth of the State. Many of the NEM1 systems have already been installed, and it is doubtful that encouraging the remaining NEM1 systems to be installed would have any quantifiable effect on economic development. (Ex. 121A at 10.)

234. Staff states that grandfathering has limited ability to enhance the continued diversification of energy production to the extent that ratepayers may choose to maintain, repair, or increase the number of their panels and output. However, the maximum installed capacity of

grandfathered ratepayers is 235 MW, and is thus the maximum diversification for that type of solar installation. (Ex. 121A at 11.)

235. Staff states that grandfathering should not be based on the individual payback for the cost of the NEM systems. Payback periods cannot be reliably calculated and Staff simply does not know what each of the approximately 17,000 NEM1 ratepayers' sales materials, contracts, and usages are, or what each individual payback period was expected or represented for each type of solar installation (purchase, lease, or PPA). The limited data points Staff does have based on sales material indicate payback periods of 5-9 years recently with longer payback periods for older systems. Staff calculated a simple payback period with many simplifying assumptions for a residential NEM ratepayer both under the legacy NEM rates and new NEM rates. For NPC's service territory, the payback period is approximately 16 and 29 years. For SPPC's service territory, the payback period is approximately 17 and 25 years. Notwithstanding, Staff believes it is practically impossible to base the duration of any grandfathering on a true payback period. (Ex. 121A at 11-13; Ex. 120A at 2-4.)

236. Staff states that NEM1 ratepayers would clearly benefit from grandfathering. Companies that lease solar equipment or systems under lease agreements would benefit from grandfathering as those leases would remain more economically advantageous to continue as part of their business models. Non-NEM ratepayers who are allocated and bear a larger portion of fixed costs that grandfathered ratepayers would be avoiding through avoided BTGR and other variable rates would be harmed by a grandfathering scheme. Grandfathered ratepayers would also contribute less to local government fees, which may impact city or county budgets to some extent. (Ex. 121A at 13-14.)

237. Staff states that it has limited information on whether the monies paid to small-

scale solar vendors stay in-State or goes out-of-State. Both SolarCity and SunRun are registered in Nevada as foreign corporations with primary offices in California. Also, in each of the SolarCity and SunRun contracts in evidence (see Ex. 64A, Attachment AMC-5 at 68, 113, 135, 136, 156, 157), one can see that any/all renewable energy credits, rebates, and environmental attributes are stripped form the power that is being sold/lease to their customers. Thus, the renewable energy credits can, and are, sold elsewhere to the sole benefit of the solar sales and leasing company. Also, both SolarCity's and SunRun's contracts state that they are able to be assigned, leased, subleased, sold, or transferred without the customer's consent. Staff does not know where the customers' payments go or who controls the contracts at this time. (Ex. 121A at 15-16.)

238. Staff states that small-scale solar developers have contractual commitments governing the transfer/sale of the home and attendant lease or PPAs. Often the potential purchaser of the home with a lease or PPA is required to have a certain credit score in order to be able to assume the lease or PPA and will have to agree to be bound by all of the terms and conditions set forth in the lease agreement. Whether or not the lease is acceptable to the potential buyer depends on the solar facility's age, equipment type, output, current price of electricity, their expected energy use and other terms of the lease/PPA. Most likely the lessor sill have filed a UCC-1 Financing Statement on the records of the property where the system is located, which gives notice of the lessor's rights relating to the solar system. Staff does not know if a UCC-1 filing affects a person's ability to obtain a mortgage, refinance, or open a line of equity. (Ex. 121A at 16-17.)

239. Staff states that if the Commission determines that grandfathering is appropriate, the preferential rate should be attached to the system, not the ratepayer. The reason for

recommending this treatment is that houses will be purchased and sold over time, so that ratepayers may not maintain their unique account numbers, and the value of the solar system will likely be included in the transaction to purchase/sell the home. It would be easier to administer the grandfathering of a rate scheme if it followed the premise, thus avoiding the need to continually monitor any home sale/purchase transactions for NEM1 ratepayers. Staff strongly recommends against grandfathering being attached to a person, as there is no guarantee that the person could not sell the house with the solar panels and then install new panels at a new residence causing confusion that could lead to arguments that the grandfathering should attach to both the old and new residence. (Ex. 121A at 18.)

240. Staff states that if the system fails, as long as the grandfathered rates attach to the premise, the only decision the NEM ratepayer would need to make is whether it would be financially viable to repair or replace the panels given whatever timeline is left on the grandfathering scheme. (Ex. 121A at 18.)

241. Staff states that there does not appear to be any practical way for Staff to confirm whether panels are new, replacements, or additions to NEM systems. Thus, the only limiting factor would be any maximum size under the NEM agreement signed by the ratepayers with NV Energy. (Ex. 121A at 19.)

242. Staff states that the Nevada-specific installation costs for both rooftop and large-scale solar PV systems have declined over the last six years. However, large-scale solar PV has seen much more dramatic reductions in installation costs than rooftop solar PV in the last few years and is currently approximately 44 percent lower in costs. There has been a recent uptick in the costs for rooftop solar, but Staff is unsure what the reason is for the increase.

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Year	Average Installation Cost ($/watt)
2010	$6.19
2011	$6.15
2012	$5.53
2013	$4.77
2014	$4.51
2015	$4.80

(Ex. 120A at 4-8; Tr. at 1481.)

243. Staff states that the costs to non-NEM ratepayers for ratepayers who choose to install rooftop solar PV systems are greater than the cost for large-scale solar PV systems as well as other renewable energy resources. Over the twenty-year period of the most recent large-scale solar PV contracts, the PPA prices are lower than NV Energy's long-term avoided cost, and thus benefit ratepayers. Such contracts are also structured to insulate ratepayers from risks. The average annual cost for each NEM ratepayer is approximately $623 and $471 for NPC and SPPC residential ratepayers, respectively. Meanwhile, the average cost for the most recent solar PV PPAs is approximately $82.24. The NEM industry exploded in 2015 (approximately 86.3 percent of all residential/small commercial rooftop solar PV systems installed under the SolarGenerations program were installed in 2015), but the installed cost per watt did not decline. NEM is one type of renewable energy resource within a mix of various renewable energy resources employed by NV Energy, and it bears some greater cost impacts to ratepayers and provides less insulation from risk than utility-scale renewable energy sources. (Ex. 120A at 8-12.)

244. Staff states that it provides consumer education to solar customers regarding NEM changes pursuant to SB 374 while fielding complaints from solar customers. (Tr. at 1510-1511.)

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TASC Supplemental Position

245. TASC recommends that a ratepayer who submitted a completed interconnection application to install a NEM system prior to January 1, 2016, should be grandfathered for a period of 20 years from the date of interconnection under the old NEM rates. Through the end of 2015, NEM ratepayers who receive incentives from the SolarGenerations program provide NV Energy with PECs with a 2.4x multiplier. These multiplied PECs will have significant additional value to NV Energy for RPS compliance. NEM ratepayers have made long-term investments in NEM systems in reliance on existing rates and with the encouragement of the existing incentive program. Many NEM ratepayers have spoken at Commission meetings about the impact that the absence of grandfathering will have on them. The imposition of different rates would be unfair. NEM ratepayers bear the risks and rewards of reasonably foreseeable changes in the levels and design of utility rates; however, the changes to the NEM rates in this Docket went far beyond what would be expected to arise out of the normal ratemaking process. Spreading the 42 percent rate increase over five years (seven percent annually) is far higher than normal as long-term utility rate increases tend to be close to the inflation rate. NEM ratepayers have been singled out for dramatic changes both in the structure of how they are compensated and in the rates that they pay. (Ex. 109A at 3-5, 9.)

246. TASC states that the Commission has the authority to apply different rates to NEM ratepayers based on when the NEM systems were installed. First, pursuant to subsection 3 of Section 2.3 of SB 374, the Commission may determine which terms and conditions of NEM2 service, including the rate structure and rates, apply to NEM1 ratepayers. In other words, the Legislature, in enacting SB 374 explicitly contemplated that the Commission could grandfather NEM1 ratepayers by deciding not to apply the NEM2 rates and tariff to NEM1 ratepayers.

Second, not all discriminatory rates are prohibited, but rather only unjust, unreasonable, or unjustly discriminatory rates and practices. Accordingly, the Commission can adopt different rates for similar ratepayers so long as there are just and reasonable grounds for such discrimination. Existing and future NEM ratepayers are situated differently, therefore, making different rates for the two groups just and reasonable. The new NEM2 rate structure radically departs from the NEM1 rate structure, exposing existing solar customers to substantial losses. Future solar customers, on the other hand, have not yet made that investment. Future customers are able to evaluate the economics of investing in a rooftop solar system under the new tariffs. Each is in a fundamentally different position. (Ex. 109A at 5-6.)

247. TASC states that no other state or regulatory authority has made major changes in the economics of NEM without grandfathering existing NEM ratepayers. In California, the California Public Utilities Commission grandfathered NEM ratepayers for 20 years from the date of interconnection. In Hawaii, the Hawaii Public Utilities Commission grandfathered NEM ratepayers indefinitely. In Arizona, the Salt River Project, Arizona's second largest electric utility, grandfathered NEM ratepayers for 20 years from the date of installation. (Ex. 109A at 6-8, 11-12.)

248. TASC states that the discounted payback for NEM systems under NEM1 rates ranges from 14 to 26 years with a median of 16 years for NPC and 20 years for SPPC. In contrast, the payback under NEM2 rates could range from 24 to 57 years with a median of 29 years for NPC and 38 years for SPPC. (Ex. 109A at 9-11.)

249. TASC states that the grandfathered NEM1 structure should stay with the existing DG system on the premises at which the system was originally installed. A NEM1 system which remains at its original premises could be transferred to new owners, operators, or accounts at the

same location, and retain its NEM1 status. If the system is physically moved to a new premise or location, the system's owners would have to take service under the NEM2 tariff. (Ex. 109A at 12-13.)

250. TASC states that NEM1 ratepayers should be allowed to repair or replace system components with comparable parts, provided the system capacity does not increase by more than the greater of 10 percent of the original system capacity or one kilowatt, or result in a system whose output exceeds the customer's on-site load. This allows for changes to the system for maintenance and repair, provided comparable parts are used, while recognizing that such replacements may nominally increase the output of the system due to increases in efficiency of the equipment or other technological changes. Changes or additions that violate these limits would result in the customer being moved to the NEM2 tariff. (Ex. 109A at 13.)

251. TASC states that grandfathering will benefit the State's goals for the development of renewable DG by avoiding a severe disruption in the economics of the 17,000 existing NEM ratepayers' long-term investments in distributed renewable resources. The percentage reduction in bill savings under proposed NEM2 rates averages 42 percent but can be much higher percentages depending on individual circumstances. These bill savings are how NEM ratepayers pay for the long-term investments in solar DG systems that the State's past solar incentive and NEM programs have encouraged and enabled them to make. A failure to grandfather existing NEM systems will have a chilling impact on the rooftop solar industry in Nevada. It is not clear that anyone is harmed by grandfathering because TASC believes there is no existing cost shift from NEM ratepayers to non-NEM ratepayers. (Ex. 109A at 13-17.)

252. TASC states that third-party ownership solar companies that offer leases and PPAs made substantial investments in Nevada and employed a considerable number of

Nevadans. Leases and PPA payments from solar customers in Nevada supported in-state operations. A significant share of the cost of a solar system is the cost of installation labor, local permitting, customer acquisition, advertising and marketing, customer support, and maintenance of existing systems, virtually all of which are expended in-state. (Ex. 109A at 17.)

253. TASC is unaware of any rooftop solar developer who has assigned its solar lease or PPAs to other entities. It is well-known and well-documented that solar leases and power purchase agreements have greatly expanded the solar industry in the United States. Generally, there do not appear to be any drawbacks for homeowners with such systems who wish to sell their homes. However, if the elimination of NEM results in the average solar customer paying total electricity bills (to both NV Energy and the solar provider) that exceed what the customer would pay without solar, this would be expected to reduce the value of a home with such higher electricity costs. (Ex. 109A at 18-19.)

254. TASC states that due to economies of scale and higher soft costs associated with rooftop solar projects, the capital costs of large, utility-scale solar projects, per installed kilowatt, are lower than the capital costs for rooftop solar projects. However, nationally the differences in costs have narrowed substantially in recent years. This is due in significant part to reductions in the soft costs of rooftop installations. Ratepayer costs are much closer between rooftop solar projects and utility-scale solar projects because one must add to the cost of utility-scale solar the marginal costs associated with delivering this power to the same customer that can be served by rooftop solar. Total utility-scale solar costs approximately 8.1 cents/kilowatt hour while rooftop solar costs approximately 8.6 cents/kilowatt hour. Further, rooftop solar installed in Nevada through 2015 is counted toward the RPS goal with a multiplier of 2.4, so existing rooftop systems are more valuable than utility-scale solar in contributing to the Nevada RPS. Finally,

rooftop solar uses the built environment, avoiding the land use and biological impacts of the significant land areas that are required by both utility-scale solar projects and the associated transmission facilities used to deliver that generation. (Ex. 109A at 19-23.)

255. TASC states that rooftop solar and other renewable distributed energy technologies allow ratepayers to take greater responsibility for their supply of electricity, compared to traditional service from the monopoly utility. There are many benefits to a technology that allows customers greater choice in how they obtain their electricity. These include new capital, new competition, grid services, high-tech synergies, customer engagement, and self-reliance. (Ex. 109A at 24-25.)

256. TASC states that it does not know what, if any, communications its members provided to their solar customers regarding NEM changes pursuant to SB 374. (Tr. at 1256-1257.)

Vote Solar Supplemental Position

257. Vote Solar recommends that the Commission grandfather NEM ratepayers who had already installed or had completed the application process for installing their NEM systems prior to the 235 MW threshold being reached for the life of the NEM systems. Vote Solar does not know how long that timeframe should last beyond the 25-30 year warranties for the NEM systems. (Ex. 112A at 1-2, 11, 16; Tr. 1349-1350.)

258. Vote Solar states that grandfathering refers to the retention of existing policies and tariffs for an existing group of ratepayers when significant changes are made to those policies and tariffs. Generally, the result of grandfathering is to apply such changes prospectively to future ratepayers (who are aware of new policies and tariffs) as opposed to both future and existing ratepayers. (Ex. 112A at 1-2.)

259. Vote Solar calculated the rate impact of a four-year laddering approach for each year in five steps for three differently-sized residential ratepayers in both NPC's and SPPC's service territory. Such an approach imposes a rate increase of nearly 25 percent and 30 percent for the smaller residential NEM ratepayers in SPPC's and NPC's service territory respectively before any cost reductions can be captured by solar generation. For larger residential NEM ratepayers in NPC's service territory, the effect is virtually nil. The annual impacts for NPC's NEM ratepayers are largest in the first year and diminish in subsequent years. For SPPC, the annual increases are somewhat more consistent. For either residential group, however, the largest bill impacts will be felt by smaller ratepayers, ratepayers with larger systems as a proportion of consumption, and ratepayers whose systems have a higher relative percentage of exports. The NEM ratepayer most affected is one who exports a majority of the PV generation—the perverse incentive created by applying the new NEM rates to such NEM ratepayers is for the NEM ratepayer to consumer more and export less. (Ex. 112A at 5-8.)

260. Vote Solar states that it would be illogical and unfair to dramatically change the price signals once the NEM ratepayer has made the investment. Ratepayer confusion usually results from a change to current practices. Grandfathering will avoid the significant changes associated with shifting some 17,000 NEM ratepayers from the old NEM rates to the new NEM rates. NV Energy's customer accounts system presumably is sophisticated enough to identify the tariff under which a ratepayer receives service to enable tracking. (Ex. 112A at 9-11).

261. Vote Solar states that it is likely that installation of new NEM systems will be different than for old NEM systems. Because the loss in value for exports is very high, it is reasonable to assume that customers desiring to go solar will downsize their systems to maximize the value received for reducing monthly consumption while minimizing value lost by

exporting energy. To make changes at this time penalizes some 17,000 NEM ratepayers for the market-based choice made at the time. (Ex. 112A at 14.)

262. Vote Solar states that utility rates for all ratepayers (not just NEM ratepayers) are subject to change. This is the nature of regulation. However, the magnitude of such changes has historically been moderated by principles of gradualism. A four-year laddering approach to changing rates for NEM1 ratepayers results in rate increases for many of the scenarios examined that are an order of magnitude well beyond what is typical through the normal ratemaking process. (Ex. 112A at 15.)

263. Vote Solar states that it is unaware of the representations by NV Energy and rooftop solar developers, if any, made to ratepayers who entered into agreements with rooftop solar developers to install NEM systems after SB 374 was enacted on June 5, 2015. (Ex. 112A at 16-17.)

264. Vote Solar states that grandfathering should stay with the premise. Rooftop solar PV systems are very difficult to relocate when the homeowner moves. Thus, there is little expectation that the initial host of a rooftop solar system would be able to bring the system (or the policy) with her to her new home. However, there is an expectation on the part of the homeowner that the investment in rooftop solar adds value to the home. (Ex. 112A at 17-18.)

265. Vote Solar states that routine maintenance and the replacement of minor parts should not trigger any change in the applicable tariffs. Solar PV technology has no moving parts and rarely, if ever, fails. Inverters tend to have shorter warranties than do panels however, and may need to be replaced after ten to fifteen years. (Ex. 112A at 18.)

266. Vote Solar states that given the cost of installing solar, it would not be surprising for a homeowner to stage a system over several years. Over time, the homeowner can add panels

to reach their desired system size. There is little impact on NV Energy or non-NEM ratepayers and this practice should be allowed without triggering the new NEM rates. (Ex. 112A at 19.)

267. Vote Solar states that grandfathering can signal the solar renewable energy industry that the rate structure in place at the time of their investment will likely stay in place for the life of the systems being deployed. It can stabilize the business and investment environment for the renewable energy industry including providers of capital. Grandfathering will also stimulate the economic growth of Nevada by reducing out-of-pocket expenses for NEM1 ratepayers. When consumers have more free cash available, they spend more, which adds to the economic vitality of Nevada. Grandfathering will also enhance the continued diversification of Nevada's energy resources as it provides assurance that the tariffs and policies in place when a customer chooses to participate in a customer-site renewable energy program will remain. (Ex. 112A at 20-21.)

268. Vote Solar states that the term "renewable energy resources" in NRS 704.766 is not limited to NEM systems. However, customer-driven renewable energy deployment is an important element of the renewable energy resources for Nevada. (Ex. 112A at 20.)

269. Vote Solar states that while one my say that NEM1 ratepayers benefit from grandfathering by retaining the arrangement in place when they made their market-based decision, it is more accurate to say that, if grandfathered, the 17,000+ NEM1 ratepayers are not harmed by the NEM2 rate structure. (Ex. 112A at 22-23.)

270. Vote Solar states that it is difficult to trace money once paid to local and national vendors of any product or service. The nature of rooftop solar deployment however requires that local skilled professionals install and maintain the systems. The capital associated with those jobs likely stays in the Nevada. (Ex. 112A at 23.)

271. Vote Solar states that on a unitized basis, a large centralized solar generating system using the same technology will likely cost less as a result of the economies of scale and lower overheads per unit. It is important to remember, however, that all ratepayers pay for their share of the centralized solar PV system, but only the host customer pays for the rooftop solar PV system. (Ex. 112A at 25.)

272. Vote Solar states that it does not engage in customer education and did not provide any information solar customers regarding NEM changes pursuant to SB 374. (Tr. at 1335-1336.)

WCSD Supplemental Position

273. WCSD recommends that the new NEM rates should not be applied to NEM1 ratepayers for a period of 20 years from energizing the NEM systems. NV Energy publicly stated its supplemental filing will reinforce the utilities' intent to grandfather existing systems under NEM1 rules for a transition period as long as 20 years. WCSD states it entered into NEM1 interconnection agreements with SPPC that clearly defined the program. In particular, the third paragraph of the cover letter for the agreements defines payment and application of excess electricity in kilowatt-hour and not cost of electricity. (Ex. 118A at 1-5.)

274. WCSD states that all NEM1 ratepayers who submitted completed applications under the 235 MW threshold should be grandfathered. These ratepayers made financial commitments and entered into long-term agreements understanding the rules of NEM and should be allowed to operate under the agreed-upon term for a period of 20 years. The 235 MW threshold was agreed upon by the Legislature, and the Commission oversaw SPPC's operation of the program under the existing rules that had been in place in a very similar format since creation in 1997. A dramatic change in the framework could not have been anticipated by those

participating under the NEM1 rules. The term of 20 years was used when the 2003 Legislature established the solar rebate program based on the projected cost of renewable energy credits for a period of 20 years when establishing the initial rebate levels under NRS Chapter 701B. However, WCSD is unsure why there was no reference to 20 years in the applicable statutes. (Ex. 118A at 5-6; Tr. at 1421-1422.)

275. WCSD states that Item 8 of the NEM interconnection agreements clarifies that any solar PV installation and obligations to maintain them are intended to transfer with the sale or transfer of property and thus should stay with the premise. If the system fails, Item 9 states that the NEM interconnection agreement is terminated. Any excess kilowatt-hour that is generated by a system constructed larger than agreed upon becomes the property of SPPC without further compensation. (Ex. 118A at 6.)

276. WCSD states that grandfathering encourages the development of solar distributed generation systems in the State. Grandfathering provides elected governing boards and their financial staff with predictability and surety required for a long term investment to install more systems. Grandfathering also enhances the continued diversification of the energy resources used in this State. Grandfathering provides elected governing boards and their financial staff with predictability and surety required for a long term investment to install more energy efficient and renewable energy systems that may have a longer payback than traditional systems. Grandfathering benefits those early adopters who invested at a time when system costs were much greater than they are now. Grandfathering benefits the students of WCSD as it allows funds that would otherwise go to paying increased utility costs to go into classroom and other operational expenses. Grandfathering provides little harm as it has a fixed cap on the number of systems and costs associated that can be spread through all ratepayers at a minimal cost as

compared to other expenses of the utility. (Ex. 118A at 7-8.)

277. WCSD states that grandfathering should not be based on the payback for the cost of the NEM system, but should be based on the assumptions provided by SPPC when entering into NEM interconnection agreements for the value of the renewable energy credits, offsets, and other benefits from the customer-generator for the life of the agreement. WCSD does not have the ability to determine the payback under the old NEM rates versus the new NEM rates as it still does not have access to electronic data to properly evaluate the usage and costs of its NEM systems. WCSD recommends that the Commission order SPPC to immediately provide data regarding the number of existing systems and the associated capacity; the number of systems completed, but waiting interconnection and the associated capacity; and the number of completed applications and the associated capacity. (Ex. 118A at 8-10.)

278. WCSD states that it received no formal notification regarding the NEM changes pursuant to SB 374 from NV Energy. (Tr. at 1416)

BCP Supplemental Rebuttal Position

279. BCP states that none of the notifications that NV Energy sent to NEM1 applicants indicate that their rate structure may change. Further, the BCP can find nothing in the tariffs for NEM service indicating that the NEM rate structure could change. (Ex. 134A at 2-3.)

280. BCP disagrees with Staff's alternative option for grandfathering NEM systems for six years. Investment decisions and commitments by NEM1 ratepayers were made in the past and cannot be revisited or modified given the long period of time usually necessary to recover the cost of the investment in a NEM system. (Ex. 134A at 4-5.)

281. BCP disagrees with NV Energy's demarcation date of September 10, 2015, for grandfathering NEM1 ratepayers. For the sake of drawing a calendar year bright line, the

Commission should consider using December 31, 2015, as the date of demarcation. BCP believes if the September 10, 2015 date is used, it is unlikely that the installed capacity of NEM1 will reach 235 MW. As of November 30, 2015, the combined total installed PV NEM capacity was 144.169 MW, nearly 91 MW under the 235 MW cap. Given the likely chilling effect of a rate change on the economic payback prospects of NEM systems, it is very likely that numerous previously-approved potential NEM1 systems who were in the pipeline awaiting installation of their systems will cancel (or default). Thus, it is unlikely that very many additional ratepayers will install solar PV. (Ex. 134A at 5-6.)

282. BCP states that it is perplexed that NV Energy is unable to calculate an estimated average payback period when NV Energy has all the data it needs for such a calculation. While Staff calculated average payback periods, Staff did not use a discount rate to account for the time value of money. Therefore, Staff's average payback periods would be even longer had the discount rate been used. BCP believes that TASC's (16-20 years) and Staff's (16-17 years) estimated payback periods are good and BCP's 18-year calculation is within the range. It is appropriate to use the class average payback periods to set the length of time for a grandfather period, and 20 years is a reasonable period of time, which is perhaps why it has been adopted by other states. For purposes of administrative efficiency highlighted by NV Energy, BCP now agrees that the 20-year timeframe should begin on January 1, 2016. (Ex. 134A at 7-9; Tr. at 1668-1669.)

283. BCP states that the claimed subsidies that NPC calculates for its seven different grandfathering options is based on the Commission's calculation of a subsidy of $623 for each residential NEM ratepayer is NPC's service territory and a subsidy of $471 for each residential NEM ratepayer in SPPC's service territory. Yet, Staff recommended that the Commission reject

the marginal cost-of-service studies to set rates for NEM ratepayers. Any alleged subsidy calculations by NPC would be much less if only those ratepayers who had installed systems as of December 23, 2015, were grandfathered. (Ex. 134A at 9-12.)

284. BCP states that it disagrees with Staff's understanding of NRS 704.766. In Section 6 of SB 255, a NEM system had to use wind or solar energy. The term "renewable energy" was not substituted in until 2001 when the Nevada Legislature adopted SB 372 to establish the renewable portfolio standard that is in existence today. The reason for this amendment was to allow for the NEM systems to be used to help Nevada electric utilities meet their renewable energy obligations. (Ex. 134A at 13-14.)

285. BCP states that it agrees with Staff's assertion that the recent addition of 129 MW of large-scale solar PV generating capacity in Nevada will not have any negative impacts to rates as long as ratepayers are not incurring additional costs for integration. NV Energy's own solar PV integration study found that the annual cost to integrate large-scale solar PV ranges from $2-20 million or $3-8/MWh. (Ex. 134A at 14.)

NV Energy Supplemental Rebuttal Position

286. NV Energy recommends that the Commission adopt a 20-year transition period and use a single-step change for NEM1 ratepayers. The Commission should define NEM1 ratepayers as those who either had (a) an interconnected NEM system or (b) a valid, pending application to interconnect a NEM facility as of September 10, 2015. For the 20-year period, NEM1 ratepayers would be included in the NEM class for the purposes of cost-of-service studies. However, the rate charged to the NEM1 ratepayer would be the same rate charged to ratepayers in the corresponding full-requirements ratepayer class. Also, the same banking rules and practices for excess energy that existed under the pre-SB 374 regime should apply. A

change management process needs to not only be fair, but, equally important, broadly perceived and accepted as fair. A 20-year period would be perceived as fair. (Ex. 129A at 6-8.)

287. NV Energy states that for purposes of administrative efficiency, the 20-year period should begin on January 1, 2016, for all NEM1 ratepayers. The vast majority of NEM systems have been installed since January 1, 2015, and manually tracking the individual dates when each NEM system was energized for purposes of establishing the timeframe will be difficult and cumbersome. (Tr. at 1622-1623.)

288. NV Energy states that the length of the transition period should not be based on a payback period. The Commission is in no position to decipher a NEM ratepayer's actual expectations regarding the value of a NEM system (whether a purchase/install, long-term lease, or PPA) at the time he/she became a NEM ratepayer. All of the calculations of payback periods or break-even analyses proposed by other parties are first and foremost post hoc. The post hoc calculations do not represent any actual NEM ratepayer's actual expectation at the time he/she decided to install a NEM system. Moreover, for many NEM ratepayers the decision might not even be based on finances. For some NEM ratepayers, the economics do not matter—they like the notion of utilizing their property to produce their own energy, reducing their carbon footprint, and, perhaps, saving a little on their power bill or enhancing the value of their home. For these NEM ratepayers, an expected payback or break-even calculation is irrelevant to the determination of a reasonable change management strategy. (Ex. 129A at 8-9.)

289. NV Energy states that the goal of change management should be to balance the interests of all ratepayers, existing NEM ratepayers and the body of ratepayers as a whole, not to preserve individual or even average payback periods on NEM ratepayers' investments. The solar industry itself provides broadly different economic payback periods depending upon their

intended audience: (1) the Commission or (2) potential and current customers. The solar industry's testimony also contradicts its published estimates in many cases. For example, Bombard states on its website the ROI is five to ten years. SunWorks (a member of GBSC) indicates 5-7 years, which is contradicted by GBSC's supplemental testimony showing an average payback of 11.85 years with some ranging from 16-18 years. While BCP indicates there is no economic payback period under the NEM2 rates, extending its model out another five years provides a payback period of 23 years, which is well within the stated useful life of solar systems that is reported on many industry websites. (Ex. 128A at 29-32.)

290. NV Energy states that while TASC' testimony contains several discrepancies. While TASC references leasing agreements and evidence that they are growing to dominate the market and have become the dominant ownership model in many states, yet all of the payback estimates presented are based on a customer-owned system. Further, TASC's work papers use a different methodology for calculating the payback period for NPC versus SPPC without any explanation for using different approaches for one utility versus the other. Finally, while TASC focuses on the reduction in bill savings under NEM2, the results of TASC's calculations show that on average NEM2 ratepayers will still achieve a significant 33percent utility bill reduction. (Ex. 128A at 32-33.)

291. NV Energy states that BCP's comparison of the subsidy (cost shift) between NEM and non-NEM ratepayers to the revenue requirement of the ON Line is pointless. The ON Line is an asset that provides value to all ratepayers. A cost shift from one set of ratepayers to another only benefits the few ratepayers from whom costs are shifted. The two are not comparable as renewable resources. However, if the annual expenses of both are compared based on unitized cost, the ON Line equals $0.0183/kilowatt hour while the NEM subsidy is

$0.05480/kilowatt hour in NPC's service territory and $0.04599/kilowatt hour in SPPC's service territory. (Ex. 128A at 20-21.)

292. NV Energy states BCP uses outdated figures in comparing large-scale solar to rooftop solar. BCP's use of vintage renewable contracts does not reflect the current price paid for solar PV contracts for comparing large-scale solar PV and other renewable energy contracts. BCP uses three contracts that were approved in 2010, 2011, and 2011. Since that time, NV Energy has executed five solar PV contracts, all at significantly lower costs than the vintage projects, thus reflecting a more accurate representation of the value of rooftop solar PV. BCP also uses REC contracts from 2007 while declaring NEM ratepayers provide a lower cost product; however, at that time only 1percent of NEM systems had been installed. A more valid comparison of judging comparability of cost would be to look at projects in the same timeframe. For the vast majority of NEM ratepayers, a comparison of 2015 large-scale contracts is more valid—70.5 percent of existing NEM systems were installed after January 1, 2015. (Ex. 128A at 21-28.)

293. NV Energy states that TASC provides inaccurate figures and assumptions in comparing large-scale solar and rooftop solar. For instance, TASC ignores the nature of the REC markets in Nevada in assigning a value for RECs; significant correction would have to be made to TASC's calculations to reflect current market prices for RECs in Nevada. Including a valid market valuation alone changes the calculated rooftop solar costs from 8.6 cents/kilowatt hour to 10.44 cents/kilowatt hour, a 30 percent premium over large-scale solar costs. Once corrections are also made to transmission and distribution costs and double-counting of RPS compliance benefits, the cost of large-scale solar is considerably lower. (Ex. 128A at 23-24, 28-29.)

294. NV Energy states that TASC's focus on the reduction of utility bill savings and the impact to NEM ratepayers' expected payback period seems to ignore that any investment comes with risk. Blaming the lack of return on a rooftop solar investment on utilities for decreasing volumetric rates is like the owner of an electric vehicle blaming their lack of return on gas stations for the lower price per gallon at the pump. In both cases, the individual's expected payback period is lengthened as one input to their calculation changed to reflect cost or changing cost. (Ex. 128A at 33-35.)

295. NV Energy states that a ratepayer's individual total savings will be predicated on the cost of installing their NEM systems, changes in behavior, and the savings that they will get on their utility bill under the rates approved by the Commission. While TASC characterizes proposed cost-based rates as extraordinary and excessive, TASC does not mention that in its own calculations NEM ratepayers paying such rates rates still experience average savings of 33 percent on their utility bill after the full phase-in period. These rates reflect the cost of providing service to this class of ratepayers and are in line with how rates are set for all ratepayers. Until cost-based rates are fully phased in, these NEM ratepayers will continue to receive subsidized rates which will continue to artificially minimize the payback period of their NEM systems and the internal rate of return on their investments. (Ex. 128A at 35-36.)

296. NV Energy states that it updated TASC's bill savings calculations to provide a comparison of NEM1 and cost-based NEM2 rates. The updated calculations demonstrate that each customer presented shows utility bill savings under cost-based NEM2 rates. However, these customers may still end up paying more in total energy costs due to the cost of their investment with a third party solar provider if that cost more than offsets any savings from the utility bill. It is the combination of these two costs that will determine the overall savings that

NEM customers can achieve from a NEM system. Of note, it is likely that some customers would be paying more in total electric costs even under the NEM1 rate structure. (Ex. 128A at 36-39.)

297. NV Energy states that the message TASC members appear to have conveyed to their potential customers is that one should expect utility rate increases of 3-10 percent annually. SunRun's marketing materials state that NV Energy's rates went up over 10 percent in Southern Nevada in 2013, referencing the EnergySage website to support this claim; an exhaustive search of this website revealed no indication of a 10 percent increase to support SunRun's claim. SolarCity marketing materials also highlight that utility rates are unpredictable and strongly imply that they increase more than the 2.9 percent fixed annual increased include in SolarCity's solar PPA plan. (Ex. 128A at 39-40.)

298. NV Energy states that Vote Solar's examples of the typical ratepayer impact are not representative of a large majority of the typical NEM ratepayers for NPC and SPPC. Further, Vote Solar's calculations contain an error; therefore, all of Vote Solar's customer impacts are incorrect showing a slightly higher impact. (Ex. 128A at 40-41.)

299. NV Energy states that TASC's recommendation that system expansions that are less than 10 percent or one kilowatt (which is greater) should be grandfathered goes well beyond maintenance and repair considerations of a system. The average residential system size in Nevada is between five and six kilowatts. Under TASC's proposal, most NEM ratepayers would be allowed to increase their system by 20 percent, or four to five additional panels, and still maintain their NEM1 status. A more reasonable allowance would be a five percent rate without the one kilowatt minimum. At five percent, maintenance considerations would be accommodated without prompting expansion opportunities. A five percent allowance would

accommodate minor variations in inverter and panel size within the same class of product. Using the average residential system size, a five percent allowance would provide 250 watts (about one panel) of latitude for future maintenance considerations without also providing expansion opportunities to gain greater capacity under the NEM1 status. (Ex. 128A at 41-42.)

300. NV Energy states that TASC's and BCP's proposals to grandfather ratepayers for 20 years based on their date of interconnection present administrative challenges. The earliest interconnections were in the late 1990s, and records are incomplete. Beginning in 2005, a more sophisticated tracking system was implemented, capturing the date of interconnection for 99.9 percent of NEM systems installed after that time. Administering TASC's and BCP's proposal for rolling migrations will require dedicated resources to manually administer over the 20-year period. The simple timeline change management alternatives do not rely on individual payback periods and apply to all grandfathered ratepayers moving forward, which are easier to understand and implement. Many NEM ratepayers may not be aware of their interconnection date. (Ex. 128A at 42-43.)

301. NV Energy states that if the Commission changes any of the rates, it is preferable to implement the changes coincident with a quarterly rate change. Any changes that will move back to banking of excess energy and establish separate rates for two types of NEM ratepayers within each class will require some time to complete accurately and to avoid ratepayer confusion. NV Energy's programming, customer service, and billing teams believe a minimum of 45 days is necessary and recommend an April 1, 2016, effective date coinciding with the next quarterly rate change. Potential outcomes that employ a laddering of rate increases that lengthen the transition period to cost-based rates can be implemented immediately as the current rates would remain in effect, albeit for a longer period of time. (Ex. 128A at 43-44.)

SEIA Supplemental Rebuttal Position

302. SEIA states that it disagrees with Staff's and NV Energy's assertion that grandfathering would not encourage the development of NEM systems in Nevada, because NEM1 ratepayers have already installed the NEM systems—SEIA references its direct testimony on the matter. SEIA disagrees with Staff's assertion that grandfathering is not likely to make the solar renewable industry more sustainable and self-sufficient—SEIA references its direct testimony on the matter. SEIA disagrees with Staff's and NV Energy's assertion that grandfathering is not likely to encourage further private investment in small-scale solar systems because the investments have already been made—SEIA references its direct testimony on the matter. SEIA disagrees with Staff's and NV Energy's assertion that grandfathering will have no significant effect on the economic growth of the State—SEIA references its direct testimony on the matter. SEIA disagrees with Staff's assertion that grandfathering has limited ability to enhance the continued diversification of energy production. Grandfathering will ensure that NEM ratepayers continue to operate those systems. Further, grandfathering will remove regulatory uncertainty as a barrier to future investment in NEM, which will contribute to the diversification of resources by ensuring that that barrier is not a deterrent to future investment. (Ex. 133A at 2-10.)

Staff Supplemental Rebuttal Position

303. Staff states that it had hoped that TASC would have provided information regarding the representations made by SolarCity and Sunrun to Nevada ratepayers as requested by the Commission. Unfortunately, TASC did not provide any information on the representations made by TASC or its member to Nevada ratepayers after the passage of SB 374. Yet, TASC proposes to grandfather any customer who applied for NEM service prior to January

1, 2016, even after the 235 MW threshold was surpassed. (Ex. 137A at 1-2.)

304. Staff states that while TASC claims the 7 percent increase in rates annually for 5 years under the laddering approach is far higher than normal, solar installers used utility rate increase assumptions ranging from 3-6.5 percent per year as the expected increase in utility rates to develop a sales proposal. It also appears to be common for solar contracts to include escalators of 2.9 percent per year for the 20 to 30 year periods of the contracts. (Ex. 137A at 2.)

305. Staff provides additional information in response to TASC's statement that utility rates tend to be close to the inflation rate. The average monthly bill adjusted for inflation for a residential ratepayer in SPPC's service territory was 38 percent lower in 2015 than in 1985. The average monthly bill adjusted for inflation for a residential ratepayer in NPC's service territory was 8 percent higher in 2015 than in 1985. (Ex. 137A at 3.)

306. Staff states that it disagrees with BCP's claim that the legacy NEM rate structure provides energy at a comparable or lower price per kilowatt hour than energy from recent large-scale solar PV contracts. BCP chose specific examples which skew the results and render its analysis incomplete and inaccurate. BCP chose PPAs that were executed in 2010 and 2011 and portfolio credit purchase agreements that were executed in 2004 and 2005. These historical contracts are not recent and a weighted average cost of all renewable PPAs that NV Energy has executed with third party developers would be a more appropriate "apples-to-apples" comparison of costs between large-scale solar PV and rooftop solar PV costs. Staff highlights a few other BCP claims in BCP's analysis regarding PECs that provide incorrect comparisons as well. (Ex. 136A at 3-4.)

307. Staff states that it disagrees with TASC's claim that there is little difference between the ratepayer cost of existing large-scale solar PV and rooftop solar PV in NPC's

service territory. TASC's calculation of the costs appears to be results-driven that uses improper and/or incorrect data to support its conclusions. TASC's claim that Nevada obtains about 90 percent of its energy from out-of-state is provided without any context to the statement which is attributed to coal, natural gas, automobile gasoline, jet fuel, and other commodities. Since the early 2000s, NV Energy has either built, acquired, or executed PPAs for a significant amount of new generation capacity that has been developed in Nevada to meet its native load requirements. TASC also adds marginal transmission and distribution costs to large-scale solar PPA in calculating the costs to ratepayers in comparison to the ratepayer costs for rooftop solar; however adding such costs is incorrect because it assumes that the transmission and distribution was built to only deliver the output of the large-scale solar PV system. Actual transmission for such for these PPAs are the network upgrade costs, which are significantly less. Finally, when calculating the ratepayer cost of rooftop solar PV, TASC added RPS benefit using a $15/MWh PEC value, which dramatically overstates the PEC value. TASC should have used the embedded PEC value of the PPA, which is $5.29/MWh. Recalculating the costs presented by TASC using the corrected figures results in total utility-scale costs of 4.8692 cents/kilowatt hour and total rooftop solar costs of 11.091 cents/kilowatt hour. (Ex. 136A at 4-6.)

TASC Supplemental Rebuttal Position

308. TASC clarifies that it recommends that a ratepayer who submitted a completed interconnection application to install a DG system prior January 1, 2016, should be grandfathered for 20 years under the original NEM tariffs. (Ex. 130A at 3-4.)

309. TASC states that NV Energy's Options 1-5 would not allow the NEM1 ratepayers to remain on the original NEM rates at all while Option 6 would allow NEM1 ratepayers to remain on the original NEM rates for only 10 years. Based on the cost shift numbers that NV

Energy now states should be the Commission's primary consideration in selecting a grandfathering proposal, this would indicated that NV Energy favors the four-year phase-in adopted in the Order, which is not grandfathering. (Ex. 130A at 4-7.)

310. TASC states that Staff's alternative option of a longer laddering period of 10 years is not grandfathering. Also, Staff's alternative 10-year and 6-year grandfathering proposals are derived from incentive programs or departing load policies that have no direct relationship to the economics of customer-sited solar. Staff's alternative based on marketed payback periods advertised by the rooftop solar vendors between 5-8 or 10 years has no supporting details on whether these anecdotal paybacks are reasonable. Finally, Staff's alternative based on the calculated payback period of the average residential NEM1 ratepayer should not be used directly to set the grandfathering period; however, Staff's calculation supports the adoption of a 20-year grandfathering term. (Ex. 130A at 7-8.)

311. TASC states that the Commission should still adopt TASC's proposal to allow systems with replacement parts to retain their NEM1 status if the replacement increases system capacity by 10 percent or less (or by 1 kilowatt or less for systems smaller than 10 kilowatts). This exception recognizes the practical reality that if a NEM ratepayer has to replace a number of panels 10 or 15 years after the system was commissioned, the original panels may no longer be available, and the replacement panels are likely to be more efficient and result in a nominal increase in system capacity. (Ex. 130A at 9.)

312. TASC states that there is significant uncertainty as to the exact date when NV Energy reached the 235 MW cap, or even if it will reach the cap at all. In the absence of a grandfathering policy which assures NEM1 ratepayers that they will be grandfathered for 20 years, many of the 9,414+ customers in the pipeline who would qualify for NEM1 rates will drop

out, leaving additional capacity available below the statutory cap. NV Energy's assertion that the cap was reached on September 10, 2015, is based on the utility only managing its queue through December 15, 2015, so additional erosion in the number of customers in the pipeline in the seven weeks since that date would push that date out. (Ex. 130A at 9-12.)

313. TASC states that it agrees with the apparent consensus of the parties that the Commission should not set the term of grandfathering based solely or directly on payback calculations. TASC also agrees with many parties that the payback evidence is one factor, along with others, that strongly supports a 20-year grandfathering term. While there will be variations in calculated paybacks, TASC, Staff, and BCP calculated consistent payback periods in the range of 16-20 years. TASC also agrees with BCP that the payback evidence clearly shows how the new NEM rates will make existing investments in rooftop solar uneconomic by extending the required payback periods to beyond the likely lives of their solar systems, which will mean customers will never receive a financial return on their investment in the absence of 20-year grandfathering. (Ex. 130A at 13-14.)

314. TASC states that the figures NV Energy used to demonstrate the cost shift to non-NEM ratepayers as a result of each of the seven grandfathering options which NV Energy presents will be subject to change in the future, and represent a substantial over-estimate of the long-term cost shift when all of the long-term values of the NEM systems are considered. (Ex. 130A at 14-15.)

Vote Solar Supplemental Rebuttal Position

315. Vote Solar states that the term "grandfathering" is not ambiguous as NV Energy asserts. It is common practice for utilities to freeze old rates as new rates are initiated, which has the effect of closing the old rates to new customers. NV Energy's attempts to reframe

grandfathering as "change management" obscures the fact that most of NV Energy's options are not grandfathering at all. Most of NV Energy's alternatives are not grandfathering at all. Options one through five are not grandfathering options, but rather are options to phase in the new rates for NEM1 ratepayers over various terms ranging from four to twenty years. There is no period of time during which NEM1 ratepayers continue to be served under their prior tariff. Thus, the Commission should not consider them as grandfathering options. Grandfathering is about treating NEM1 ratepayers who have made large investments and commitments fairly while considering the effects on non-NEM ratepayers. As to the 10 and 20-year options with no laddering, those are a step in the right direction, but grandfathering should be permitted for the life of the NEM system. The NEM1 ratepayers designed their systems based on price signals in place at the time of their application for NEM service, and it is unfair to alter that signal when ratepayers cannot respond. (Ex. 132A at 2-5.)

316. Vote Solar states that Staff's six-year grandfathering proposal is tied to two GRC cycles. While Staff indicates this gives NEM1 ratepayers time to modify their behavior and investments, Staff provides no explanation or further detail into the sort of modifications it might suggest NEM1 ratepayers make. (Ex. 132A at 7.)

317. Vote Solar that Staff's calculations show the magnitude of the impact of the new rates on NEM1 ratepayers. It is reasonable to infer that had these rates been in effect at the time of the customer's investment decision, far fewer customers would have installed NEM systems. (Ex. 132A at 7-8.)

318. Vote Solar states that it fails to see how not grandfathering NEM1 ratepayers encourages investment in large-scale solar PV as Staff asserts. The approval of any revenue – neutral tariff would have no impact on utility scale resources of any kind. However, increasing

costs for NEM systems might encourage NEM1 ratepayers to invest in storage and defect from NV Energy's system entirely. This response would only exacerbate any revenue reduction that new tariffs are meant to address. (Ex. 132A at 10-11.)

319. Vote Solar disagrees with NV Energy's use of September 10, 2015, as the point of demarcation for NEM ratepayers who qualify for NEM1 service. This is consistent with the establishment of a cap at 235 MW. Those ratepayers who have submitted applications under the 235 MW cap should have an opportunity to participate as allowed by law, even if that requires additional replenishment and backfilling. It would be arbitrary to cut off eligibility for grandfathering based on what NV Energy's estimate happens to be on the date it filed supplemental direct testimony in these proceedings. (Ex. 132A at 12-13.)

320. Vote Solar is concerned with BCP's to tie the grandfathered rate structure to the premise as long as the customer stays with the premise. This proposal effectively takes value away from NEM1 ratepayers who sell their property during the lifetime of their rooftop solar system. The value added to a home by a rooftop system is inexorably tied to the reduction in utility expenses stemming from that investment. If prospective homebuyers cannot save on electrical bills by being grandfathered, it will diminish the value of the home. The Commission should simply tie the grandfathered tariffs and policies to the premise. (Ex. 132A at 13.)

321. Vote Solar agrees with NV Energy that an end-of-life scenario would be an appropriate reason to terminate the applicability of the grandfathered rates to the premise. However, if a NEM system is simply down for a short period for repairs or turned off for a brief period (e.g. during an extended vacation or foreclosure), NV Energy's proposal begins to put vague limitations on the applicability of grandfathering to NEM1 ratepayers. The applicability and limitations of grandfathering, must be very clear to NEM1 ratepayers so that they understand

their own obligations and responsibilities to remain grandfathered. (Ex. 132A at 13-14.)

322. Vote Solar disagrees with NV Energy's proposed blanket expansion policy to move NEM1 ratepayers to NEM1 rates if the NEM system is expanded. Customers who planned (and budgeted for) their installation in stages should not be forced to shift to the new more financially onerous NEM2 tariffs and policies. This is readily distinguishable from other forms of system expansion by setting the capacity of the inverter as the maximum allowable panel capacity. Provided the addition of new panels to the existing panels does not result in total panel capacity exceeding inverter capacity, the additional should be allowed without triggering the new NEM rates. Under any other situation, TASC's 10 percent approach makes sense. BCP's proposal to put an individual ratepayer on two different tariffs if a NEM1 ratepayer adds panels later is unworkable because the proposal does not explain what portions of the ratepayer's delivered load would be subject to the prior and the new tariffs, what portions of any exported energy would be subject to the prior and new tariffs, or what the basic service charge would be. (Ex. 132A at 16-17.)

Commission Discussion and Findings

Statutory Authority

323. Pursuant to SB 374, the Commission has very broad authority to establish new rate classes, terms and conditions, and rates and charges for NEM ratepayers. (See Sections 2.3, 2.95(1)(b), and 4.5 of SB 374.) The Nevada Legislature directed the Commission to establish just and reasonable rates and charges to avoid, reduce, or eliminate any unreasonable shifting of costs from NEM ratepayers to non-NEM ratepayers.

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Overview

324. To the extent it is reasonably possible, rates charged to a class of ratepayers should recover the costs to serve that class of ratepayers. Current rates for NEM ratepayers are not properly aligned with the costs to serve NEM ratepayers. The misalignment can be attributed in part to the NEM policies enacted by the Nevada Legislature prior to the passage of SB 374. As NEM system penetration increases the cost-shift will grow. Consequently, it is in the public interest to take steps to transition to accurate, cost-based, non-discriminatory rates.

325. While rates charged to a class of ratepayers should reasonably recover the costs to serve that class of ratepayers, the design of cost-based rates is not a simple, mechanical process. Rate design encompasses many factors, not all of which can be quantified. The general principles of rate design are (1) economic efficiency, (2) equity, (3) bill stability, (4) revenue stability, and (5) customer satisfaction. It is generally understood that these principles are sometimes in tension with each other and that regulators must strike the appropriate balance between these principles. For example, rate stability is not an end in itself and has to be weighed along with the other criteria. Striking the appropriate balance requires consideration of many factors.

326. The simplest way to develop an equitable pricing structure is to adopt prices that mirror the cost structure. Specifically, the fixed costs should be collected through fixed charges and costs which vary with consumption should be collected through volumetric charges. In this proceeding, NV Energy proposes a three-part tariff that includes (1) a basic service charge, (2) a demand charge, and (3) a volumetric charge. This proposal most closely mirrors the nature of costs incurred by NV Energy to serve NEM ratepayers. However, the Commission rejects this proposal.

Demand Charge

327. Residential and small commercial ratepayers in Nevada have not had a demand charge (demand cost recovery component) in the past.[29] A certain level of ratepayer education would be necessary to implement a demand charge for the NEM ratepayer classes. NEM ratepayers are sophisticated enough to understand demand charges and can reduce their demand impacts in many ways, including how they configure their installations[30] and whether they elect to modify their ongoing usage patterns. However, ratepayer acceptance of this potential rate change is unknown. As a result, now is not the time to adopt a demand charge for residential and small commercial NEM ratepayers, given the other changes taking place in this proceeding.

328. Instead, the Commission approves a two-part tariff consisting of a modified basic service charge and a volumetric commodity charge.

Basic Service Charge

329. The basic service charge shall be calculated by NV Energy to recover the full amount of customer, facilities, and primary and high voltage distribution costs. These costs do not change for a ratepayer after the installation of a NEM system; however, because installation of a NEM system results in less energy delivered by the utility to the NEM ratepayer, a NEM ratepayer will avoid paying for these fixed costs if rates remain designed to collect them through a volumetric charge. A basic service charge is the simplest and most easily understood method to ensure recovery of such fixed costs from a ratepayer regardless of the volume of sales to the ratepayer.

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[29] A demand charge is one option designed to recover costs that are based on a ratepayer's unique maximum load. The maximum load is what the utility must be prepared to serve, and the maximum load also triggers a sudden and intense need for electricity. This sudden and intense need for energy is filled by the utility's ability to ramp up and ramp down generating units. For decades, demand charges have been used for large industrial or commercial ratepayers due to the costs and strains put on the utility's systems due to their particular demand characteristics.

[30] Orientation of solar panels can increase generation at different times of the day to suit the load needs of the individual ratepayer. (Ex. 99A at 72.)

330. Primary and high voltage distribution costs, while fixed in nature, are allocable to each ratepayer class based upon that class's contribution to demand, which may change over time. Assigning a demand charge reflects both the fixed nature of the costs and usage of the allocated primary distribution costs to the ratepayers within the class. Including primary and high voltage distribution in the basic service charge is in lieu of instituting a facilities charge based on demand. As the Commission has forestalled instituting demand charges at this time, including these costs in the basic service charge reflects the nature of these costs better than including them in the variable commodity rate. Another benefit for including the costs in the basic service charge is a reduction in volatility for NEM ratepayers, providing more predictable and stable electric bills because the increase in the basic service charge yields a corresponding reduction in the variable commodity rate.[31]

331. The Commission does not have enough information to make an informed decision regarding NV Energy's proposal to include 100 percent of transmission and 62 percent of generation demand costs in the basic service charge. Therefore, in the next general rate cases for SPPC (2016) and NPC (2017), NV Energy shall recommend (with additional support) what portion of transmission and generation demand costs should be shifted (tilted) between the basic service charge and volumetric commodity rate. A future determination on rate tilt is particularly important in the case of NEM ratepayers because they are partial-requirements ratepayers who, in many cases, can avoid all or nearly all volumetric commodity rates for some months of the year. Until the Commission makes the necessary adjustment to the volumetric rates in the next

[31] The primary drawback to including the costs in the basic service charge is the creation of some level of intra-class inequity and some price signal distortion—NEM ratepayers are unable to potentially avoid some of the costs by controlling demand. Conversely, the primary drawback to including the costs in the variable commodity rate is the creation of a relatively higher level of intra-class inequity—higher-usage NEM ratepayers will pay a portion of the costs associated with serving lower-usage NEM ratepayers.

general rate cases, the volumetric commodity rates will continue to be used to recover 100 percent of the transmission and generation demand costs. Nothing in this discussion precludes a party from requesting the implementation of demand charges for NEM ratepayers in the future.

TOU

332. The NEM TOU rate schedules proposed by NV Energy are approved as modified by the other rate design decisions in this Order. TOU rates are an improvement over the flat rates in providing price signals that better reflect the variations in costs across the year. TOU rates represent a far more accurate, targeted, and cost-based means to charge NEM ratepayers. NEM ratepayers can understand more complex cost structures, such as TOU, and change their behavior to produce savings based on a price signal. TOU periods can also be adjusted as peak demand changes in the future.[32]

333. Pursuant to NRS 704.085, as modified by SB 374, there are no restrictions on the implementation of TOU rates for NEM ratepayer classes. The changing technology landscape makes time-variant pricing a viable and important element of future NEM rate design. Therefore, in the next general rate cases (SPPC in 2016 and NPC in 2017), NV Energy shall recommend whether TOU rates for NEM ratepayers should continue to be opt-in, opt-out, or mandatory in the future.[33]

Net Excess Energy

334. Banking the net excess energy at the retail rate as some parties propose is not just and reasonable because the energy delivered by the NEM ratepayers is not the same as the

[32] For example, NPC is forecasting the peak demand to shift to later in the day to the early evening hours by 2017 as more solar generation impacts the utility's system. (Ex. 83A at 2.)

[33] The Commission notes that the investor owned utilities in California have been ordered to file applications no later than January 1, 2018 that propose default TOU rate structures to begin in 2019. (See Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-Of-Use Rates, Rulemaking 12-06-013, issued 7/13/2015).

energy delivered by NV Energy. Pursuant to NRS 704.001(4), NV Energy is required to provide reasonably reliable service at just and reasonable rates. NV Energy is required to provide this service at the times and place and in the volumes required by any ratepayer, including a NEM ratepayer. This requires that the utility adhere to industry standards for the design and operation of its electric system including system reserves and redundancies. Failure to provide this service can result in fines and the revocation of NV Energy's operating certificate. In contrast, NEM ratepayers have no legal requirement to provide any volumes to the grid at any time. NEM ratepayers provide these volumes solely at the discretion of each individual NEM ratepayer and are not scheduled in advance and can be withdrawn at any time by the NEM ratepayer. Further, the volumes flow to the grid without consideration for overall grid demand or system reliability which remains the legal responsibility of NV Energy.

335. NRS 704.769 requires measuring the difference between the electricity supplied by a NV Energy and the electricity generated by a NEM ratepayer which is fed back to NV Energy over the applicable billing period. This measuring can be accomplished in various increments over the applicable billing period (ie. 15-minute, hourly, multiple periods of hours in a day, daily, monthly).

336. Staff's proposed buy/sell arrangement with NEM ratepayers for energy is just and reasonable and in the public interest. NV Energy shall use the average annual long-term avoided energy cost that is forecasted by PROMOD[34] from NV Energy's last approved integrated resource plan filings with an adder for avoided distribution line losses. NV Energy shall account for this monthly credit on NEM ratepayers' bills as a fuel and purchased power expense which would go into the BTER and DEAA accounts accordingly. Staff's proposal allows NEM

[34] PROMOD forecasts the value that the utility thinks it will have to pay for energy in the future. (Tr. at 540-541.)

ratepayers to avoid energy costs and gives appropriate credit for the net excess energy from the NEM systems. The arrangement avoids conflating two separate and distinct transactions: (1) the sale of energy services by NV Energy to a NEM ratepayer and (2) the sale of energy and other attributes by the NEM ratepayer to NV Energy. Through hourly settlement, the arrangement has the potential to nearly eliminate the very type of cost shifting that SB 374 was designed to address, including revenue under-recovery associated with retaining transmission and generation demand costs in the commodity rate, even when a less-efficient, two-part pricing structure is used. Also, the arrangement has the benefit of efficiently and transparently valuing the net excess energy and any other attributes produced by the NEM systems in advance.

337. The NEM ratepayers' net excess energy is set at a value that captures the variables that make up the possible value/detriment of NEM during each general rate case. The Commission will set a value during each future general rate case by using a methodology that considers both the positive and negative effects of: (1) avoided energy; (2) energy losses/line losses; (3) avoided capacity; (4) ancillary services; (5) transmission and distribution capacity; (6) avoided criteria pollutant costs; (7) avoided carbon dioxide emission cost; (8) fuel hedging; (9) utility integration and interconnection costs; (10) utility administration costs; and (11) environmental costs. These variables must be known and measurable positive and negative effects internal to the utility; these variables cannot be speculative or unquantified. For other than the avoided energy and energy losses/line losses, there is insufficient time or data in this proceeding to assign a value to the other nine variables, but other information can be vetted in future general rate cases.

338. Using an optional alternative to the annual price for net excess energy would enhance the price signal sent to NEM ratepayers by informing the NEM ratepayer or potential

NEM ratepayer as to the value of net excess energy. Some price diversity could be achieved by establishing "time-of-production" ("TOP") pricing with the time periods mirroring the TOU periods used by NPC and SPPC in their respective TOU rate designs. Therefore, NV Energy shall establish TOP rates for NEM ratepayers. The rates shall be based on the long-term avoided costs for each hour, grouped into the same seasonal time periods used for the TOU rates. The tariffs shall require NEM ratepayers who select service under the TOP rates to also take service under the TOU rates.

Gradualism

339. Consistent with the principle of bill stability described above, the Commission finds that it is in the public interest to establish a time frame in which to gradually move to the revised rate structure in order to prevent rate shock and allow current and future NEM ratepayers ample time and opportunity to adjust their current usage patterns.[35]

340. The transition will be similar to the process of climbing a ladder to the ceiling. The ceiling reflects the revised rates for NEM ratepayers as provided in the discussion above and the floor reflects existing rates for NEM ratepayers. The first rung of the ladder will be implemented on January 1, 2016, and continue through December 31, 2018. Beginning on January 1, 2019, the second rung will be implemented and continue through December 31, 2021. Beginning on January 1, 2022, the third rung will be implemented and continue through December 31, 2024. Beginning on January 1, 2025, the fourth rung will be implemented and

[35] The rooftop solar PV industry has benefited from and now thrives under two major subsidy programs fostered by the Nevada Legislature. The first subsidy comes in the form of a full-requirements rate structure that results in cost shifts away from NEM ratepayers to non-NEM ratepayers. This subsidy has been in place in Nevada since 1997, when the Nevada Legislature passed SB 255 creating the retail credit NEM mechanism. The second subsidy comes in the form of the rebate through the SolarGenerations program. This subsidy has been in place for over a decade (established by the Nevada Legislature in 2003), and the amounts paid (which will total $255 million upon exhaustion) have steadily decreased over time. This program has created a glide path. The migration (through gradualism) to cost-based rates instituted in this proceeding continues that glide path to take the rooftop solar industry toward self-sustainability in Nevada.

continue through December 31, 2027. The fifth and final rung will be implemented on January 1, 2028, when the transition to cost-based rates will have been completed. As a result, incremental changes from the current rates will be made consistent with the general rate case cycles of both utilities. Gradualism will mitigate rate shock by providing a glide path to cost-based rates that are not subsidized by non-NEM ratepayers.

Risk of Rate Changes

341. NEM ratepayers have installed NEM systems over the last 17 years under the old NEM rates. All ratepayers (including NEM ratepayers) bear the risks and rewards of making investment decisions based on existing electric rates and tariffs with the knowledge that electric rates and tariffs can change at any time based on changed circumstances. The State of Nevada, through the SolarGenerations program, has already designated $255 million in incentives (funded by ratepayers) paid to most NEM ratepayers to help mitigate these risks to encourage small-scale (rooftop) solar development in Nevada.

342. The Commission notes that all NEM ratepayers must sign an interconnection agreement with NV Energy. NEM ratepayers and the system owners (where the NEM ratepayers are not the system owners) are required to execute a standard form letter agreement addressing their interconnections. Since 2004, each iteration of the interconnection agreement includes the governing authority (Section 9), which states that the NEM tariffs may be amended by the Commission at any time. From 2004-2008, Section 9 stated:

> Utility's distribution tariffs may be amended by the PUCN at any time.

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From 2009-present, Section 9 stated:

> This Agreement shall be governed and construed under the laws of the State of Nevada as they may be amended or superseded from time to time. The Public Utilities Commission of Nevada . . . or the Utility may amend its tariffs upon Commission approval, which amendments are subject to public noticing requirements.

343. Evidence presented in these proceedings suggests that the small-scale (rooftop) solar vendors (with the exception of Bombard) failed to inform these customers of the potential changes to the old NEM rates as contemplated by SB 374.[36] The vendors' failure to properly inform their customers is particularly egregious because many small-scale (rooftop) solar vendors, including SolarCity and Sunrun, were at the Legislature for the hearings on SB 374 and supported SB 374 in its final version, which included language at Section 2.3(3) clearly explaining that new rates (that eliminate cost shifts) will potentially apply to <u>all</u> NEM customers:

> 3. In approving any tariff submitted pursuant to subsection 1, the Commission shall determine whether and the extent to which any tariff approved or rates or charges authorized pursuant to this section are applicable to customer-generators who, on or before the date on which the cumulative capacity requirement described in paragraph (a) of subsection 1 of NRS 704.773 is met, submitted a complete application to install a net metering system within the service territory of a utility.

Regardless, by moving forward with the installations and submission of completed applications, NEM ratepayers specifically assumed the risks that NEM rates could change pursuant to SB 374.

Perpetuity

344. Only GBSC and Vote Solar argue that NEM1 ratepayers should never move to cost-based rates, instead arguing that NEM1 ratepayers should remain on the old NEM rates for the life of the NEM systems. This is unreasonable. The actions of a ratepayer should not be used to prevent the Commission from establishing just and reasonable rates for all ratepayers.

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[36] The Commission notes that NV Energy began in July to provide such disclosures regarding SB 374 in the interconnection agreements that every NEM1 ratepayer signed.

Further, the size of the annual subsidy, currently at over $16 million, will cumulatively grow unreasonably larger over time. GBSC intimates that NEM system lives "could easily stretch out beyond 40 years" based on NEM1 ratepayers' anticipated recovery of their NEM system investments. At 40 years, not only is a system's viability questionable, but also the subsidy borne by non-NEM ratepayers will have grown to $640 million (assuming just 235 MW of installed NEM capacity). This is a perpetual cost shift with inaccurate price signals that prolongs old NEM rates already in place for nearly 20 years. The Commission is establishing rates in this proceeding, and system life has nothing to do with establishing just and reasonable rates.

No Change for 8-10 or 20 Years

345. In this proceeding, the Commission has revised the rates and terms of NEM service on a prospective basis. A wholesale change immediately for NEM ratepayers would result in rate shock. Similarly, an abrupt change at 8-10 years (as originally proposed by BCP) or 20 years (as proposed by BCP, NV Energy, SEIA, TASC, and Vote Solar) would also result in rate shock. These proposals simply delay the necessary correction identified by the Commission by "kicking the can down the road." At the end of the time period, arguments to continue the old NEM rates for an even longer period are inevitable due to the impending rate shock of suddenly transitioning to cost-based rates. While TASC characterizes these proposals as a smooth transition from the old NEM rates to the new NEM rates, these proposals are anything but smooth; a rate cliff is not a smooth transition

346. These proposals will only forestall the argument again when after NEM ratepayers have had 8, 10, or 20 years of bills unreflective of actual costs and accurate price signals. Such a delay is unreasonable. These proposals do nothing to address the problem of antiquated rates that were instituted nearly 20 years ago to jumpstart an industry. The old NEM

rates are not reflective of accurate price signals or actual costs to serve. As the number of NEM systems has exploded in the last year, the subsidy has become unreasonable. That subsidy is borne by non-NEM ratepayers who are predominantly middle and low income families.

347. Several parties point to the 20-year periods instituted in Arizona (Arizona Public Service Company), California, and Hawaii in an attempt to demonstrate that NEM ratepayers had an expectation that Nevada would follow suit with these other states.[37] Hawaii cannot be included because its decision was made in October, after the 235 MW threshold was met, so none of the NEM1 ratepayers would have known about Hawaii's decision at the time these NEM1 ratepayers signed up for NEM service. As SEIA previously stated, NEM is available in 43 states, so there are 40 states, including Nevada, which have not adopted such 20-year proposals.

348. Rates and rate structures change over time in electric utility ratemaking. While all ratepayers would like to lock in rates and rate structures to insulate themselves from change over 20+ years, electric utility ratemaking cannot work in this manner—otherwise, ratepayers left out of such schemes will be forced to pay ever-increasing incremental costs as the number of ratepayers increases and the ongoing costs to serve those ratepayers increases over time. Non-NEM ratepayers should not be required to subsidize NEM ratepayers for the decisions that NEM ratepayers made any longer than is reasonably necessary to move NEM ratepayers to cost-based rates over a period of time.

349. Proposals that introduce a rate cliff at 8-10 or 20 years do nothing to address the unreasonable $16 million annual subsidy that would be borne by non-NEM ratepayers. Over 8-

[37] The Commission also notes that the language of SB 374 stating that the Commission "[s]hall not approve a tariff filed pursuant to subsection 1 or authorize any rates or charges for net metering that unreasonably shift costs from customer-generators to other customers of the utility" is unique language to Nevada.

10 years, the subsidy grows to $128-160 million. Over 20 years, the subsidy grows to $320 million. A cost shift of this size is unreasonable. The annual subsidy equates to a 1.7 percent annual rate increase for the average single-family residential ratepayer in NPC's service territory.

Payback

350. The small-scale (rooftop) solar interests argue that the Commission should grandfather NEM ratepayers in order to guarantee a return on their NEM system investments. All investments come with risk. Non-NEM ratepayers should not be asked to act as a safety net to fund the unreasonable cost shifts needed to guarantee a return on NEM investments. The goal of moving to cost-based rates should be to balance the interests of all ratepayers, existing NEM ratepayers, future NEM ratepayers, and non-NEM ratepayers, not to preserve individual or even average payback periods on NEM ratepayers' investments.

351. Payback periods cannot be reliably calculated. Payback periods will vary from customer to customer and are not a reasonable basis for imposing new tariffs. The terms and conditions of the contractual commitments governing rooftop solar installations are extremely variable, accomplished through one of three primary commercial structures: purchase/installs, power purchase agreements, and leases. There is no uniformity in the costs of equipment or installations, the duration of financing agreements, or interest rates or other terms and conditions. It is impossible to identify a typical purchase/install transaction. Also, for some NEM ratepayers, the economics matter, while for others they do not. NEM ratepayers utilize their NEM systems to produce their own energy, reducing their carbon footprint, saving money on their electric utility bill, and/or enhancing the value of their home. The Commission is establishing rates in this proceeding, and NEM system paybacks have nothing to do with establishing just and reasonable rates.

352. A review of the information provided in this proceeding demonstrates broadly different economic payback periods promoted by the solar industry in web-based promotions (Bombard (5-10 years), SolarCity (7-10 years), SunWorks (5-7 years)) compared to the figures in the sworn testimony of witnesses in this proceeding (BCP (14 years), GBSC (11.85years), TASC (16 years), and Staff (16 years)). It appears that some small-scale (rooftop) solar vendors advertised unrealistic payback periods.

Transition to Cost-Based Rates

353. The Commission selects a process for first reducing and then eliminating the cost shifting that occurs under the old NEM rates.

354. Utility rates for all ratepayers (not just NEM ratepayers) are subject to change. This is the nature of rate regulation. However, the magnitude of such changes has historically been moderated by principles of gradualism. Gradualism is the concept used by utility regulatory commissions to manage change associated with moving utility prices to reflect new or changing rate structures of costs of service.

355. Without gradualism, there is no move to accurate, cost-based price signals. Currently, the average NEM ratepayer uses just 58 percent (in NPC's service territory) and 51 percent (in SPPC's service territory) of the energy generated from his/her NEM system on-site. The rest is physically delivered to the electric grid. This is an inefficient use of the energy generated by the NEM systems that places all of the cost burden of the unreasonable subsidy on remaining ratepayers. A gradual move to cost-based rates over time will allow NEM ratepayers to make informed decisions on how to maximize the output of their NEM systems, particularly with the option of TOU rates.

356. NEM ratepayers will need time to adapt to the new NEM rates. At the same time,

the growing cost shift will be borne by non-NEM ratepayers who will be subsidizing NEM ratepayers. Therefore, the Commission must balance these competing ratepayer interests. Under a laddering approach, incremental steps (rate changes) can be made over a period of time. The first step was implemented on January 1, 2016. One step every year over a four-year period minimizes the subsidy to $27 million but does not provide much opportunity for NEM ratepayers to adapt in between rate changes. One step every two years over an eight-year period doubles the subsidy to $54 million but provides a better opportunity for NEM ratepayers to adapt in between rate changes. One step every three years over a twelve-year period raises the subsidy to $81 million which is very large, but NEM ratepayers have three years in between steps, which mirrors the timeframe that all other ratepayers have between rate changes in NV Energy's three-year GRC cycle.[38] One step every four years over a sixteen-year period raises the subsidy to $109 million, with NEM ratepayers having four years between steps, which is more time than all other ratepayers have between rate changes in NV Energy's three-year GRC cycle. The longer it takes to migrate NEM ratepayers to cost-based rates, the higher the subsidy that will be paid by non-NEM ratepayers.[39]

357. Consistent with the principle of bill stability, the Commission finds that it is in the public interest to establish a time frame in which to gradually move to the revised rate structure in order to prevent rate shock and allow current and future NEM ratepayers time and opportunity to adjust their current usage patterns. All NEM customers, regardless of when their solar energy

[38] For instance, the Commission authorized a period of time (1983-1992) for the migration of rates for Elko residents to the higher system-wide rates for the corresponding rate classes in SPPC's territory, with step changes implemented after each GRC--any increase in rates resulting from the GRCs was increased by an additional 17.5 percent until the rates for Elko residents reached parity with all other SPPC ratepayers in the same rate classes. (See Docket No. 83-111, Stipulation Regarding Rate Increases for the Elko District of Sierra Pacific Power Company, May 10, 1983; Docket Nos. 91-7079, 91-7080, and 91-7081, Order issued January 31, 1992, at 128-130.)

[39] The estimated subsidies are based on 235MW of installed NEM system capacity. If new installations result in capacity exceeding 235MW, the subsidies will be larger.

systems were installed, will benefit from a gradual approach toward cost-based rates. This approach will create a path to developing sustainable practices in the small-scale roof top solar industry that will allow companies and NEM ratepayers the opportunity to review and revise their business models to compete without NEM subsidies. The Commission finds that it is in the public interest to apply the same rates and tariffs to all NEM ratepayers, regardless of the vintage of the NEM system (whether or not their completed NEM applications were submitted prior to the 235 MW cap being met). NV Energy is generally not allowed to discriminate between similarly-situated ratepayers but is allowed to differentiate between classes of ratepayers if either the costs to serve or the usage patterns are sufficiently different. There will be no difference between NEM ratepayers in NV Energy's costs to serve them or their usage patterns. The ratemaking principle of horizontal equity supports treating equals (all NEM ratepayers) equally. Also, providing different price signals, through different rates and tariffs, to similar ratepayers is illogical and potentially confusing. Treating all NEM ratepayers the same will reduce the costs of administering two separate schedules for similarly-situated ratepayers, while eliminating confusion regarding eligibility.

358. All NEM customers will transition to cost-based rates over the next 12 years. During that period there will be a total of five step changes to NEM2 rates: (1) January 1, 2016, (2) January 1, 2019, (3) January 1, 2022, (4) January 1, 2025, and (5) January 1, 2028. The adoption of a five-step ladder for managing change over a period of time reflects the principle of gradualism, gradually increasing prices and reducing net excess energy credits, achieving cost-based rates (thereby eliminating the unreasonable cost shift) in 12 years, by January 1, 2028. A 12-year timeframe for all NEM customers to date represents an approximately $100 million subsidy that non-NEM ratepayers will have to pay to cover the costs to serve NEM ratepayers

that are not recovered from NEM ratepayers during the transition period. It is reasonable to transition NEM ratepayers to cost-based rates over this time period in order to mitigate rate shock.

359. One step every three years is the most reasonable in balancing the interests of both NEM1 ratepayers and non-NEM ratepayers regarding the period of time for NEM1 ratepayers to adapt to the new NEM rates and the amount of the continued subsidy that must be paid by non-NEM ratepayers over that same period of time. A step change every three years is also consistent with the time period between rate changes for electric utilities through general rate cases. All ratepayers should expect this. Further, the timing of the three-year steps provides NEM ratepayers with an unprecedented preview of future rates (actual amounts will vary due to intervening quarterly BTER and DEAA filings). The actual NEM rates will be revised during each subsequent GRC. For SPPC, the rates from its 2016 GRC will be known by January 1, 2017, but NEM ratepayers in SPPC's service territory will not experience the corresponding step change until January 1, 2019, a full two years later. For NPC, the NEM rates for its 2017 GRC will be known by January 1, 2018, but NEM ratepayers in NPC's service territory will not experience the corresponding step change until January 1, 2019, a full year later.

360. The 12-year timeframe enables NEM ratepayers to maximize the value of their NEM systems by providing time to adjust usage patterns to maximize use of energy on their premises while allowing more time for new technologies (battery storage, etc.) to become viable add-ons. The 12-year timeframe also helps implement the Legislature's goal of allocating the full $255 million in incentives under the SolarGenerations program for 235 MW of small-scale (rooftop) solar in Nevada by December 31, 2021 (see NRS 701B.005(1).) Installations were progressing at a relatively steady pace to reach that goal (which is still almost six years away)

until the massive run-up over the last 18 months.

361. TASC's calculations demonstrate that NEM ratepayers paying NEM rates still experience average savings of 33 percent on their electric utility bills after the full phase-in period. These rates reflect the cost of providing service to this class of ratepayers and are in line with how rates are set for all ratepayers.

362. The transition period also acknowledges the investment NEM ratepayers have made in their NEM systems. While not a reason for the 12-year timeframe, the 12-year timeframe has the effect of providing a much greater opportunity for NEM ratepayers to achieve a more reasonable or expected payback for certain systems while reducing the estimated $320 million cost to non-NEM ratepayers by 2/3rds.

Transparency

363. In an effort to provide transparency regarding the costs of the NEM subsidy that all residential and small commercial non-NEM ratepayers will pay over the next 12 years, NV Energy is directed to include a separate line item entitled "NET ENERGY METERING SUBSIDY" on all non-NEM ratepayers' monthly electric bills. NV Energy will include the lineitem calculations for approval in the 2016 SPPC GRC and 2017 NPC GRC and every subsequent GRC until the NEM ratepayers have transitioned to NEM rates on January 1, 2028.

Fairness

364. While the 12-year transition period is fair to all ratepayers, NV Energy states that the rates also have to be "perceived" as fair. Under normal circumstances, the Commission agrees that perception (customer acceptance) is another tenet of rate design to be weighed amongst sometimes competing principles. In all cases, accurate and timely information regarding rates, rate changes, statutes, and statutory changes are necessary for individuals to

make informed choices that best meet their individual needs and circumstances. In this instance, a major rate change affecting all ratepayers was under consideration in this proceeding. Unfortunately, with few exceptions, timely and accurate information was not provided to ratepayers by small-scale (rooftop) solar advocates or the utility. Moreover, the Commission cannot base its decisions on misperceptions that are largely the product of an active effort to mislead ratepayers through the dissemination of inaccurate information.

365. TASC, SolarCity, and SunRun, as well as others, have engaged in an all-out campaign to influence public perception of the Commission's ratemaking process by claiming repeatedly that the Commission is subject to regulatory capture by NV Energy and that the Commission's decisions in this proceeding are illegal, all while the proceedings before the Commission were ongoing. The lack of customer acceptance was compounded by the complete lack of any information provided by the small-scale (rooftop) solar vendors (except Bombard) to potential solar customers that NEM rates may change pursuant to SB 374. Such actions by TASC, SolarCity, SunRun, and other small-scale (rooftop) solar vendors have effectively eliminated any possibility of customer acceptance. However, this Commission will not allow such actions by TASC, SolarCity, SunRun, and other small-scale (rooftop) solar vendors to dictate a certain outcome in this proceeding. The Commission has reviewed all of the evidence admitted into the record in these proceedings and makes its decisions based on that evidence in compliance with the relevant laws and regulations.

366. BCP and NV Energy also failed to provide timely information to existing and potential NEM ratepayers. BCP, who represents NEM ratepayers in this proceeding, made no observable effort to educate or inform existing and potential NEM ratepayers of the potential that NEM rates may change pursuant to SB 374. BCP has also made no observable efforts to

investigate the marketing practices of the small-scale (rooftop) solar industry.[40] Likewise, NV Energy failed to update its website in a timely manner regarding the new NEM rates. NV Energy only did so upon direction from the Presiding Officer in the form of Procedural Order No. 7, issued January 8, 2016. NV Energy should be required to provide, as a compliance, information regarding its NEM rate education efforts. Within 10 days of the issuance of this Order, NV Energy shall submit a report of its efforts to date to educate ratepayers of the NEM rate changes and its plans to continue these efforts over the next 12 months. This effort shall include information and other resources to assist existing NEM ratepayers in understanding how to improve their energy use patterns and practices to maximize the benefits of the NEM systems under the new rate structure.

Misrepresentations

367. The narrative of the small-scale (rooftop) solar interests that the Commission must honor the expectations of NEM ratepayers to "lock-in" rates over a period of time is based on a false premise. Many of the small-scale (rooftop) solar vendors appear to have offered prospective customers forecasts that do not account for future uncertainty, thereby overstating expected savings. The Commission will not reward the bad behavior of some small-scale (rooftop) solar vendors by requiring non-NEM ratepayers to subsidize NEM ratepayers for longer than is necessary to avoid rate shock.

Changes to NEM Systems

368. In adopting a transition process that treats all NEM customers the same, the

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[40] It should be noted that during the 2015 Nevada Legislature, BCP supported Assembly Bill ("AB") 330, which would have instituted certain customer protections. (Minutes have not been posted.) BCP's comments regarding the need for oversight of the small-scale (rooftop) solar industry may be viewed at 1:40:43 of the March 27, 2015 meeting of the Assembly Commerce and Labor during which BCP expressed concerns regarding the marketing practices of small-scale (rooftop) solar installers and marketers. The hearing on AB 330 starts at 1:15:44. It is unclear whether BCP's concerns with the marketing practices of small-scale (rooftop) solar installers and marketers have changed since March of 2015.

Commission avoids the need to address the logistics of changes to NEM systems. Equal treatment of all NEM customers means that there are no separate eligibility requirements for receiving the subsidized transition to cost-based rates.

Policies of This State

369. Cost-based rates that may increase costs for NEM systems relative to other renewable technologies will encourage private investment in other renewable technologies such as large-scale solar PV and storage technologies, which will stimulate the economic growth of Nevada and enhance the continued diversification of the energy resources used in Nevada. The Commission has consistently pursued the least-cost renewable energy options that benefit all ratepayers in Nevada (i.e. rejection of the large-scale solar PV PPA in late 2014 at over $110/MWh and approval of five large-scale solar PV PPAs in 2015 and 2016 at under $50/MWh based on the levelized cost of energy). In the last five months alone, the Commission has approved 329 MW of large-scale solar projects.

370. The NEM rates encourage small-scale (rooftop) solar PV vendors to compete more evenly (the 30 percent Federal Investment Tax Credit has been extended for wind and solar companies) in the marketplace with other renewable energy resources, especially with large-scale solar PV developers. Unfortunately, the exodus of small-scale (rooftop) solar vendors in Nevada in the past two months demonstrates that their business models are premised on subsidies from non-NEM ratepayers. As long as those subsidies exist in other states, there is no reason for these businesses to adapt in Nevada. This is a short-sided business strategy that is harmful to the long-term viability of solar energy. Fortunately, large-scale solar developers have developed a viable long-term strategy in Nevada, as evidenced by the Commission's approval of the five 20-year solar PV PPAs in 2015 and 2016. These low PPA prices are passed on to all

ratepayers. This is in stark contrast to the significant subsidies that non-NEM ratepayers are being asked to pay to NEM ratepayers who install NEM systems on their premises.

371. Prior to the enactment of SB 374, the old NEM regime was in place for nearly 20 years, having first been adopted as a pilot program in 1997. The cost shifting is the product of a 1997 pilot program that required NV Energy to provide service to NEM ratepayers with a specific rate structure designed to encourage what was then a new technology and a nascent industry. In 2015, the Nevada Legislature for the first time authorized the Commission to address the cost shifts associated with the old NEM rates. The text of SB 374 shows that one of the primary objectives of the statute was to reduce and eliminate the subsidies created by the old NEM rates. Subsection 2(e) of Section 2.3 of SB 374 provides that the Commission "[s]hall not approve a tariff filed pursuant to subsection 1 or authorize any rates or charges for net metering that unreasonably shift costs from customer-generators to other customers of the utility." Subsection 2(d) of Section 2.3 of SB 374 also expressly gives the Commission the authority to establish rates and charges for customer-generators that "avoid, reduce or eliminate" the "unreasonable shifting of costs from customer-generators to other customers of the utility" that occurs under the old NEM rates.

372. The Commission notes that the small-scale (rooftop) solar industry supported SB 374. Mr. Robert S. Uithoven, representing TASC (which included SolarCity and Sunrun at the time), stated ". . . we are happy to be here in support of the legislation." (Minutes of the Assembly Committee on Commerce and Labor, May 25, 2015, at 6.)

373. Some have questioned the State's commitment as well as the Commission's commitment encouraging private investment in renewable energy resources, stimulating the economic growth of this State, and enhancing the continued diversification of the energy

resources used in this State. The Commission can answer these questions unequivocally by stating that the Commission has and will continue to carry out all of the State's policies involving utility regulation pursuant to NRS Chapters 701B, 703, 704, and 704B, not just a subset of those provisions. The Commission simply cannot promote NEM in Nevada at any cost; the Legislature expressly prohibited the Commission from adopting rates that unreasonably promote NEM and authorized the Commission to avoid, reduce, or eliminate an unreasonable shifting of costs from NEM ratepayers to non-NEM ratepayers.

374. The State has spent an enormous amount on renewable energy. The costs for the NEM subsidy paid by non-NEM ratepayers will be in addition to the $255 million for incentives paid by ratepayers for the period between 2010 and 2025 for solar programs mandated by NRS 701B.005(2)(b). Also, both NPC and SPPC have entered into numerous renewable contracts to meet Nevada's RPS requirements. For NPC's ratepayers over the 12-month period ending September 30, 2015, the costs for these renewable contracts was $212 million. (Docket No. 15-01009, Monthly Deferred Energy Reports for September 2015, Exhibit E-4.) NPC estimates renewable contracts costs of $296 million for 2016 (see Docket No. 15-06015, NPC Comments filed August 5, 2015). The value of these renewable contracts is more than $6 billion over the next 25 years (see Docket No. 15-05006, Order issued January 20, 2016, at Attachment 2). For SPPC's ratepayers over the 12-month period ending September 30, 2015, the costs for these renewable contracts was approximately $65 million. The vintage of these particular contracts varies, but assuming that SPPC will continue at this level over the next 25 years or so to ensure continued compliance with the RPS, expenditures for SPPC's ratepayers will exceed $1.5 billion.

375. The costs for these renewable energy contracts are borne by all ratepayers, and the NEM1 subsidy will be added to these costs for the residential and small commercial ratepayers

in Nevada. Nevada's ratepayers generously support renewable energy resources in this State every month through their electric utility bills.

VI. MISCELLANEOUS ISSUES

A. New-Build Solar

SNHBA Position

376. SNHBA recommends a separate tariff for NEM systems on new-build homes. SNHBA states that distinct treatment of new-build solar is necessary to accurately reflect the unique value of new-build solar and the benefits for NV Energy's general body of ratepayers. It is unreasonable to assume that the costs and load characteristics for existing residential ratepayers who retrofit their homes using solar are the same as residential ratepayers occupying new homes that have solar included as a package design for compliance with modern building codes. It is self-evident that the demand on a utility's electric system from a new, modern home built in the last 15 years will differ substantially from that of a home built in the nineteen-sixties, seventies, eighties and even the nineties. However, SNHBA could provide no information demonstrating that any of its developers have asked NV Energy to modify the distribution facilities used to provide service to new-build solar homes. (Ex. 41A at 2-3; Tr. at 196-205.)

377. SNHBA states that NV Energy, through its filings, discovery responses, and witness testimony, is on record numerous times admitting that it lacks data to substantiate application of the proposed NEM2 rate to new-build solar. There is also no research or previous study to support the application of cost assumptions based on retrofit to new construction. NV Energy's estimates of increased service costs for NEM ratepayers are entirely based on existing customers. These retrofit-based cost assumptions are unreasonable if applied to new construction due to the inherent economies of scale and significant differences in opportunities

for design optimization and quality control in new construction compared to existing homes. (Ex. 41A at 4.)

378. SNHBA states that it is reasonable to assume that new-build solar has much less demand on a utility's system especially during peak hours in sunny, desert states like Nevada because new homes are subject to stringent building codes and benefit from the availability of more energy efficient building materials and appliances compared to homes built 40-50 years ago or even 10-20 years ago. New-build solar is a more holistic approach to solar deployment whereby a home is designed from the start to optimize solar generation and energy efficiency. Having data on this point would be immensely helpful, but NV Energy admits that it does not gather such granular information, even though NV Energy states on numerous occasions in the Applications that the best and most accurate way to develop rates is by gathering and analyzing actual production and usage data over multiple years. (Ex. 41A at 10-12.)

379. SNHBA states that Nevada has a unique opportunity in this proceeding to officially recognize that not all rooftop solar is the same and to develop separate rates accordingly. Doing so would position Nevada as among the most forward-looking and thoughtful states when it comes to understanding the many nuances of solar power. (Ex. 41A at 15-16.)

380. SNHBA states that a separate rate for new-build solar would also lead to a number of economic benefits for Nevada. A uniform rate for rooftop solar would invariably drive up the cost of new-build homes that include rooftop solar by limiting the financial benefit of these homes for consumers. Driving up the cost of new-build homes, in turn, would price many consumers out of the housing market, especially those in the market for greener homes. (Ex. 41A at 19.)

BCP Position

381. BCP states that the Commission should consider a lower Rule 9 allowance for new home construction where rooftop solar is installed at the time a dwelling is built, reflecting lower usage and less revenue to justify the allowances. This issue could be dealt with in a general rate case. (Ex. 41A at 14.)

Staff Position

382. Staff states that it is unreasonable for NV Energy to downsize the design for its distribution facilities that serve new residential housing communities who offer rooftop solar systems. NV Energy's distribution facilities need to be sized to reliably serve the entire load of a NEM ratepayer in the event that the NEM ratepayer's on-site generation fails; otherwise, there could be reliability impacts and/or service disruptions to the NEM ratepayer and potentially all other ratepayers on the distribution path. Further, in response to a Staff data request, the builders represented by SNHBA indicated that they do not downsize the electrical service ratings for new homes to reflect installation of a rooftop solar system. (Ex. 83A at 5-6.)

NV Energy Rebuttal Position

383. NV Energy states there is no need to create a separate rate class for new-build solar homes. The Commission has never considered differentiating electric service and charges based on vintage (i.e., when they become a ratepayer). A ratepayer who buys a new home with modern energy efficiency built in pays the same rates as ratepayers in older, less efficient homes. If a ratepayer retrofits his older home to have the same efficiency standards as a new home, the ratepayer still pays the same energy rates as before the retrofit and the same rates as the ratepayer who bought the more efficient home. Absent some marked change in the distribution service provided, retrofitted rooftop solar homes should not be treated differently than new-build rooftop

solar homes. (Ex. 99A at 36-38.)

384. NV Energy states that developers have not asked NV Energy to design and install distribution facilities smaller than otherwise are required pursuant to NV Energy's distribution design guidelines/standards. The absence of any significant difference in the type of service provided to new-build NEM ratepayers, compared to other NEM ratepayers, suggests that it is inappropriate to create a separate class for NEM ratepayers with new-build solar. (Ex. 84A at 15-16; Tr. at 773-777, 1054-1055.)

Commission Discussion and Findings

385. It is not just and reasonable to establish a separate tariff for new-build solar. There is insufficient data upon which to establish a separate rate class at this time. NV Energy's distribution facilities need to be sized to reliably serve the entire load of a NEM ratepayer in the event that the NEM ratepayer's on-site generation fails; otherwise, there could be reliability impacts and/or service disruptions to the NEM ratepayer and potentially all other ratepayers on the distribution path. The absence of any significant difference in the type of service provided to new-build NEM ratepayers is supported by the fact that developers do not downsize the electrical service ratings for new residential homes to reflect installation of solar PV systems. Absent some marked change in the distribution service provided by NV Energy, there should be no separate ratepayer class for new-build solar.

B. Generation Meter

NV Energy Position

386. NV Energy recommends a monthly charge applied only to non-incentivized NEM2 ratepayers for the cost of generation meters. NV Energy states that generation meters will facilitate compliance with SB 374's requirement that NV Energy assess the effect of

distributed generation on its NEM systems, accurately measure the cost of service, and potentially aid in demonstrating compliance with the Clean Power Plan. (Ex. 2A at 21; Ex. 5a at 21.)

BCP Position

387. BCP states that unless something like a value-of-solar approach (or NV Energy's proposal to charge for total energy including solar) is adopted, the extra generation meter proposed by NV Energy and included in costs is unnecessary. All that is necessary is to use the AMI data so that energy delivered by the utility to the customer and excess energy sent to the utility are paid different amounts. Some generation meters may be required for load research, but it is not clear that all NEM ratepayers need them. If an extra meter is required, it should be paid for up front by the NEM ratepayer, not financed by the utility. (Ex. 62A at 6.)

TASC Position

388. TASC states that there is no need to require all NEM2 ratepayers to install a generation meter. Historically, the rationale for generation meters has been to allow NV Energy to claim the PECs from NEM ratepayers who receive an incentive under the SolarGenerations program. (See NRS 704.775(3)(a)). However, this program will be ending in the near future. Presumably, NV Energy's primary rationale for requiring these meters in the future is to perform load research, which only requires metering a small, statistically valid sample of a ratepayer class—perhaps one percent. Given that a significant number of NEM1 ratepayers already have generation meters, it is questionable whether NV Energy would need additional generation meters for NEM2 ratepayers in order to obtain a statistically valid sample. If NV Energy needs the metering data for any future Critical Peak Production credits from NEM, all ratepayers would benefit by reducing NV Energy's Clean Power Plan compliance costs. As a result, the costs of

the metering needed to secure such credits should be borne by NV Energy because all ratepayers will benefit. If NEM2 ratepayers want a generation meter in order to account for the PECs that they own, or simply to collect the output data from their generator, NV Energy should offer to split the cost of the generation meter 50/50. No other utility requires ratepayers to pay for a generation meter without a clear program purpose for that meter. (Ex. 62A at 26-29; Ex. 68A at 35-38.)

Vote Solar Position

389. Vote Solar recommends eliminating the generation meter requirement and associated cost and rate. Vote Solar states that it does not find NV Energy's explanations compelling. Generation meters are not needed. To develop load shapes, NV Energy needs to know how much energy it is supplying to the NEM ratepayer and at what time. The total hourly profile is not needed. A dual register meter or a second meter to measure exports on a temporal basis will provide the additional information NV Energy needs to net exports against future consumption. A single bi-direction meter would be sufficient. To the extent that the generation meters are desirable to measure total on-site generation for the purposes of Clean Power Plan compliance, such use benefits all ratepayers, so the costs should be spread to all ratepayers. (Ex. 44A at 59-61.)

NV Energy Rebuttal Position

390. NV Energy continues to support the incremental monthly charge as proposed in the direct filing. NV Energy needs to continually monitor and review the sample data that is provided by all meters, in particular as a certain population, or segment of a population, is growing. That is certainly the case with the NEM ratepayer class. By simply using the generation meters that are already installed as the sample, the growth and potential

diversification of the loads is ignored. For this reason alone, the monthly charge applied only to non-incentivized NEM2 ratepayers is justified and reasonable. The amount of energy that NEM ratepayers provide to serve their load is also an important piece of the total load equation and is a vital input to the load shapes that are used in developing the MCSS for NEM ratepayers. (Ex. 99A at 51-54.)

391. NV Energy states that ratepayers who choose to participate in the SolarGenerations program are required to have a generation meter so that the PECs can be measured, verified, and reported. The PECs are retained by NV Energy on behalf of all ratepayers who fund the incentive payment to participants in the SolarGenerations program. This requirement for participants in the SolarGenerations program to have a generation meter will continue to remain the case for NEM2 systems because the SolarGenerations program is still active and was not affected by SB 374. (Ex. 85A at 11.)

Commission Discussion and Findings

392. NV Energy's proposed generation meter installation requirement and cost allocation is denied at this time. The Commission is not convinced at this time that the installation of generation meters for all NEM ratepayers is necessary. This decision has no impact upon NV Energy's requirement to have generation meters installed for those ratepayers receiving incentives pursuant to the SolarGenerations incentive program. To preserve the option for NV Energy to install generation meters in the future (should the need arise), NV Energy shall include in its NEM tariffs a provision requiring the NEM ratepayer to authorize NV Energy's ability to install and maintain a generation meter, if deemed necessary by the utility.

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C. Interconnection Charges

BCP Position

393. BCP states that the Commission should consider some type of reasonable one-time administrative fee to recover one-time accounting and service costs associated with hooking up a NEM ratepayer. This issue would be ripe for resolution in a general rate case. (Ex. 62A at 14.)

TASC Position

394. TASC recommends that the Commission authorize NV Energy to implement an upfront interconnection charge for new NEM ratepayers as follows:

Customer Class	Interconnection Charge
RS	$80
RS-M	$90
GS	$130

Upfront processing charges for interconnection applications are not uncommon (Excel Energy in Colorado and Avista and Idaho Power in Idaho), with a typical fee of no more than $100 for residential NEM ratepayers. While the meters used for NEM ratepayers are the same as those used for non-NEM ratepayers, additional programming and inspections are required at the time of installation of the NEM system. Such additional costs are logically associated with the initial interconnection process and are best collected through an upfront fee for interconnection. The Commission should revisit these costs in subsequent general rate case cycles to ensure that they remain cost-based. (Ex. 76A at 28-29; Ex. 68A 34-35.)

NV Energy Rebuttal Position

395. NV Energy states that the appropriate recovery of these costs would be the same as recovery of the meter installation costs for any non-NEM ratepayer, which is through a basic service charge and not a one-time interconnection fee as proposed by TASC. Meter costs are

ongoing and do not end once initial installation is complete. NV Energy is responsible for the ongoing maintenance of a NEM ratepayer's installed meter, including the cost of replacing the meter as necessary. (Ex. 99A at 84).

Commission Discussion and Findings

396. It is not reasonable to establish an interconnection charge for NEM ratepayers at this time in lieu of collecting such meter costs in the basic service charge. Besides the additional costs associated with meter programming and testing, NV Energy is responsible for the ongoing maintenance of NEM ratepayers' installed meters, including the costs of replacing the meters as necessary. An ongoing charge in the basic service charge will adequately reflect such costs incurred by NV Energy. Parties can review these costs in subsequent general rate case cycles to ensure that they remain cost-based.

D. Regulatory Liability

NV Energy Rebuttal Position

397. NV Energy states that it will create a regulatory liability for each utility. This will be a reserve account to offset NV Energy's revenue requirement in future general rate cases. Periodically, each utility will calculate the difference between the revenue it would have collected under the NEM1 rates and rules and the revenue that it actually collects under the NEM2 rates and rules. The amounts will be recorded in a regulatory asset/liability (Account No. 186). NV Energy will track and account for incremental NEM2 revenue in this manner regardless of which NEM2 proposal the Commission adopts in this proceeding. NV Energy will not benefit from any changes to the NEM rate structure. Instead, non-NEM ratepayers will benefit by seeing even lower rates in the future. (Ex. 101A at 5-6.)

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Commission Discussion and Findings

398. It is just and reasonable to establish regulatory liability accounts for each utility until NEM rates approved in the next general rate case (2016 for SPPC and 2017 for NPC) go into effect. The accounts will be used to collect the difference between the revenue NV Energy would have collected under the NEM1 rates and rules and the revenue that NV Energy actually collects under the new NEM rates and rules. Several parties complained that any shift in rate design for NEM ratepayers between general rate cases would lead to an increase in revenues to be retained by NV Energy and its shareholders. One of the purposes of these proceedings is to establish just and reasonable rates and charges "to avoid, reduce, or eliminate an unreasonable shifting of costs from customer-generators [NEM ratepayers] to other customers [ratepayers] of the utilities." (See Section 2.3(2)(d) of SB 374). Though SB 374 does not mention ensuring that there are no unreasonable shifting of costs from NEM ratepayers to NV Energy between general rate cases, the Commission finds that it is in the public interest to approve NV Energy's proposal to ensure that non-NEM ratepayers, and not NV Energy, receive the benefit of NEM ratepayers' increased contributions to their share of costs until the next general rate cases. Parties may make recommendations on the proper allocation of the monies in the regulatory liability accounts in the next general rate cases.

E. Load Data

WCSD Position

399. WCSD recommends that the new NEM tariffs not be applied to any NEM ratepayers who have not been equipped with smart meters and have access to less than one year of load data. SPPC has yet to install smart meters at all WCSD schools with NEM systems, and the most recent estimate for installation is the first quarter of 2016. The lack of smart meters is

problematic for WCSD because with no access to real-time data, energy management, especially for rate schedules that include demand charges, is nearly impossible. (Ex. 40A at 2, 5.)

400. WCSD further recommends that the Commission direct SPPC to make real-time, fifteen-minute interval data available to all "summary billed" ratepayers. As a "summary billed" ratepayer, WCSD receives one summary bill for payment purposes for its 129 facilities with 395 SPPC meters. SPPC's software does not allow "summary billed" customers to have access to the My Account program and thus does not have access to real-time data. Without access to real-time data, WCSD is unable to effectively manage its demand profile to ensure the most efficient use of energy. Access to such data will allow WCSD and other "summary billed" customers to explore options to control demand and associated charges. (Ex. 40A at 6.)

NV Energy Rebuttal Position

401. NV Energy disagrees with WCSD. Through the SolarGenerations program, over 500 ratepayers billed under a current three-part rate structure made similar decisions to WCSD to install NEM systems, all without the data from AMI that WCSD insists must be available. SPPC's records indicate that WCSD has 230 active metering points and that all but 74 have already been upgraded to a smart meter and presently record in fifteen-minute intervals. The upgrades on the remaining meters are ongoing, with a scheduled completion date of March 31, 2016. (Ex. 85A at 3-4; Tr. at 849-851.)

Commission Discussion and Findings

402. The Commission finds that this issue is moot because the new NEM rates do not include a demand charge component at this time.

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VII. ROOFTOP SOLAR INDUSTRY JOBS

Staff Position

403. Staff states that caution should be employed when referencing employment figures for the solar industry in Nevada. The Solar Foundation ("TSF") provides an oft cited employment figure of 5,900 persons at the end of 2014 for Nevada's solar industry. The figures are based on an annual census conducted by The Solar Foundation. However, it is a national census, not a state census. The census includes jobs from a variety of solar businesses, many of which would not be affected by NEM tariff changes while others are not solar businesses at all.[41] Also, the employment numbers are not stated in full-time equivalent units, and there is no other study to confirm the claimed employment. The Solar Foundation was unable to provide Staff with any granular data when asked for more detailed state information and the state specific data regarding the state employment estimate. Staff also requested more detailed state-specific employment statistics from both TASC and SEIA for each solar company in their respective memberships. Both TASC and SEIA objected to providing that information, even by aggregated category. (Ex. 81A at 2-7).

Commission Discussion and Findings

404. The information and testimony presented by Staff regarding the employment figures for Nevada's solar industry indicates that the figures cannot be reasonably relied upon as an estimate of the number of solar jobs in Nevada or the number of jobs that could potentially be impacted by this Order. Further, no corroborating information from other sources was identified. No party to this proceeding provided any material support for the notion that a change in the

[41] The list of Nevada companies included a number of large utility-scale solar developers as well as Southwest Gas Corporation, Western Nevada Supply Company, and the Commission. (Ex. 81 at Attachment AC-5; Tr. at 721-724.)

NEM rates and tariffs would result in the loss of nearly 6,000 solar jobs. TASC and SEIA's objections to providing information that would help confirm or refute the figures for rooftop solar jobs in Nevada are perplexing.

405. All arguments of the parties raised in these proceedings not expressly addressed herein have been considered and either rejected or found to be non-essential for further discussion in this Order.

THEREFORE, it is ORDERED that:

1. The Application of Nevada Power Company d/b/a NV Energy in Docket No. 15-07041 is APPROVED AS MODIFIED by this Order.

2. The Application of Sierra Pacific Power Company d/b/a NV Energy in Docket No. 15-07042 is APPROVED AS MODIFIED by this Order.

Compliances:

3. Within seven days of the effective date of this Order, Nevada Power Company d/b/a NV Energy shall file with the Commission revised tariff sheets consistent with this Order.

4. Within seven days of the effective date of this Order, Sierra Pacific Power Company d/b/a NV Energy shall file with the Commission revised tariff sheets consistent with this Order.

5. The Regulatory Operations Staff shall review the above-referenced revised tariff sheets for consistency with the Commission's Order. The revised tariff sheets shall become effective upon the completion of the Regulatory Operations Staff's review.

6. Within 10 days of the effective date of this Order, Nevada Power Company d/b/a NV Energy shall file with the Commission a report of its efforts to date to educate ratepayers of

the net energy metering rate changes and its plans to continue these efforts over the next 12 months.

7. Within 10 days of the effective date of this Order, Sierra Pacific Power Company d/b/a NV Energy shall file with the Commission a report of its efforts to date to educate ratepayers of the net energy metering rate changes and its plans to continue these efforts over the next 12 months.

Directives:

8. In a future general rate case, Nevada Power Company d/b/a NV Energy shall study and account for the costs and benefits of higher penetration of net energy metering systems on its distribution systems and include the results when completed to assist in determining whether rates need to be further modified for net energy metering ratepayers.

9. In a future general rate case, Sierra Pacific Power Company d/b/a NV Energy shall study and account for the costs and benefits of higher penetration of net energy metering systems on its distribution systems and include the results when completed to assist in determining whether rates need to be further modified for net energy metering ratepayers.

10. In its next general rate case, Nevada Power Company d/b/a NV Energy shall recommend (with additional support) what portion of transmission and generation demand costs should be shifted (tilted) between the basic service charge and volumetric commodity rate.

11. In its next general rate case, Sierra Pacific Power Company d/b/a NV Energy shall recommend (with additional support) what portion of transmission and generation demand costs should be shifted (tilted) between the basic service charge and volumetric commodity rate.

12. In its next general rate case, Nevada Power Company d/b/a NV Energy shall recommend whether time-of-use rates for net energy metering ratepayers should continue to be opt-in, opt-out, or mandatory in the future.

13. In its next general rate case, Sierra Pacific Power Company d/b/a NV Energy shall recommend whether time-of-use rates for net energy metering ratepayers should continue to be opt-in, opt-out, or mandatory in the future.

14. In Nevada Power Company d/b/a NV Energy's next general rate case filing with the Commission, Nevada Power Company d/b/a NV Energy shall propose a line item entitled "NET ENERGY METERING SUBSIDY" that will calculate the subsidy that each non-net metering ratepayer pays each month to subsidize net metering ratepayers. Nevada Power Company d/b/a NV Energy will include the same proposals in every subsequent general rate case filing with the Commission until the net energy metering ratepayers have been migrated to net energy metering rates on January 1, 2028.

15. In Sierra Pacific Power Company d/b/a NV Energy's next general rate case filing with the Commission, Sierra Pacific Power Company d/b/a NV Energy shall propose a line item entitled "NET ENERGY METERING SUBSIDY" that will calculate the subsidy that each non-net metering ratepayer pays each month to subsidize net metering ratepayers. Sierra Pacific Power Company d/b/a NV Energy will include the same proposals in every subsequent general rate case filing with the Commission until the net energy metering ratepayers have been migrated to net energy metering rates on January 1, 2028.

16. Failure to comply with the compliances and directives in this Order may subject Nevada Power Company d/b/a NV Energy to administrative fines pursuant to Nevada Revised Statute 703.380 and/or revocation of the underlying relief granted as appropriate.

17. Failure to comply with the compliances and directives in this Order may subject Sierra Pacific Power Company d/b/a NV Energy to administrative fines pursuant to Nevada Revised Statute 703.380 and/or revocation of the underlying relief granted as appropriate.

18. The Commission may correct any errors that have occurred in the drafting or issuance of this Order without further proceedings.

By the Commission,

PAUL A. THOMSEN, Chairman

ALAINA BURTENSHAW, Commissioner

DAVID NOBLE, Commissioner and
Presiding Officer

Attest: Trisha Osborne
TRISHA OSBORNE,
Assistant Commission Secretary

Dated: Carson City, Nevada
2.17.16

(SEAL)

PUBLIC UTILITIES COMMISSION PUC OF NEVADA

Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

EXHIBIT
APS-12
ADMITTED

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

R. Thomas Beach
Patrick G. McGuire
May 8, 2013

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

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

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

In assessing the benefits and costs of solar DG from a ratepayer perspective, it is important to use a time frame that corresponds to the useful life of a solar DG system, which is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side. When a utility assesses the merits of adding a new power plant, or a new energy efficiency (EE) program, the company will look at the costs to build and operate the plant or the program over their useful lives, compared to the costs avoided by notoperating or building other resource options. A central problem with the Beck and SAIC Studies is that they assess the benefits of solar DG only in a single-year "snapshot," without considering the long-term benefits of the solar resource over its full expected life.

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

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

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

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

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

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

1. Methodology

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

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

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

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

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

1 The original Beck study looked at solar DG benefits in 2010, 2015, and 2025. The new SAIC study examined solar DG benefits in 2015, 2020, and 2025.

2 2012 IRP, at pages 6 (Table 2) and 20.

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

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

For the Beck and SAIC Studies, APS used the PROMOD production cost model to calculate the avoided energy costs of DG. APS has declined to provide any of the details of these production cost results, citing confidentiality concerns with releasing information that might compromise APS's position in short-term energy markets. Although production cost results can be useful for short-term forecasting and budgeting, such tools have less relevance in projecting long-run avoided costs that focus on the costs avoided by not having to build or buy certain long-term resources. Instead of such short-term modeling, we have calculated APS's long-run avoided energy costs using natural gas forward market data, and the heat rates, variable O&M costs, and other operating parameters for the long-term fossil resources that solar DG will avoid. Other similar studies have taken a comparable approach to calculating long-term avoided energy costs.[3]

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

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

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

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

2. Benefits of Solar DG

a. Energy

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

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

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

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

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

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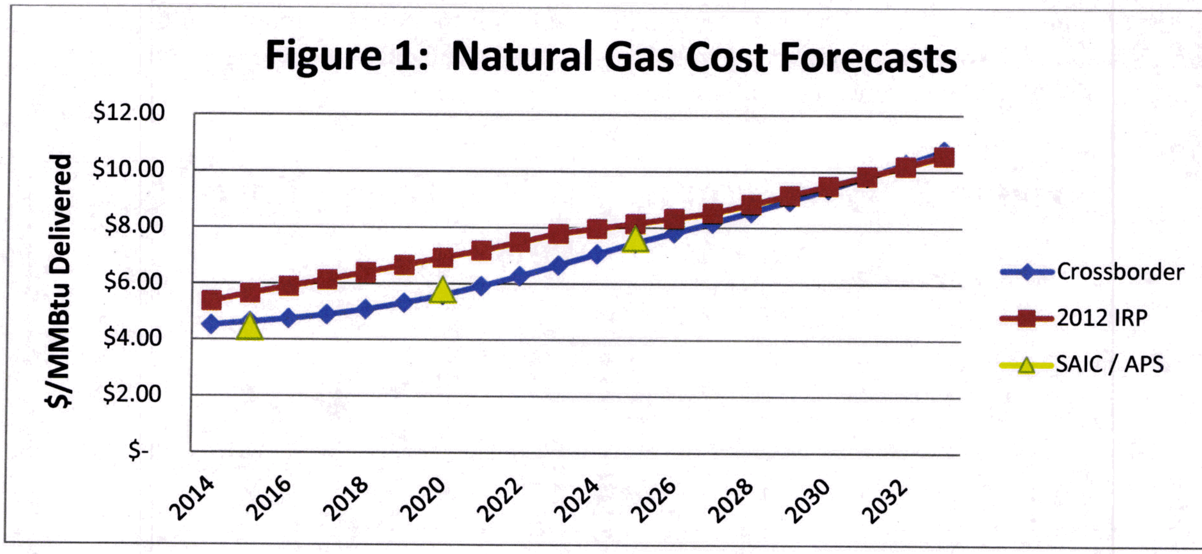
4 The discount rate in the Beck Study was 7.86% (page N-4); the 2012 IRP assumed 7.95% (page 145), and SAIC used the current APS weighted average cost of capital of 7.21% (SAIC April 11, at 77).

5 2012 IRP, at 64.

6 2012 IRP, at Figure 14.

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



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

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

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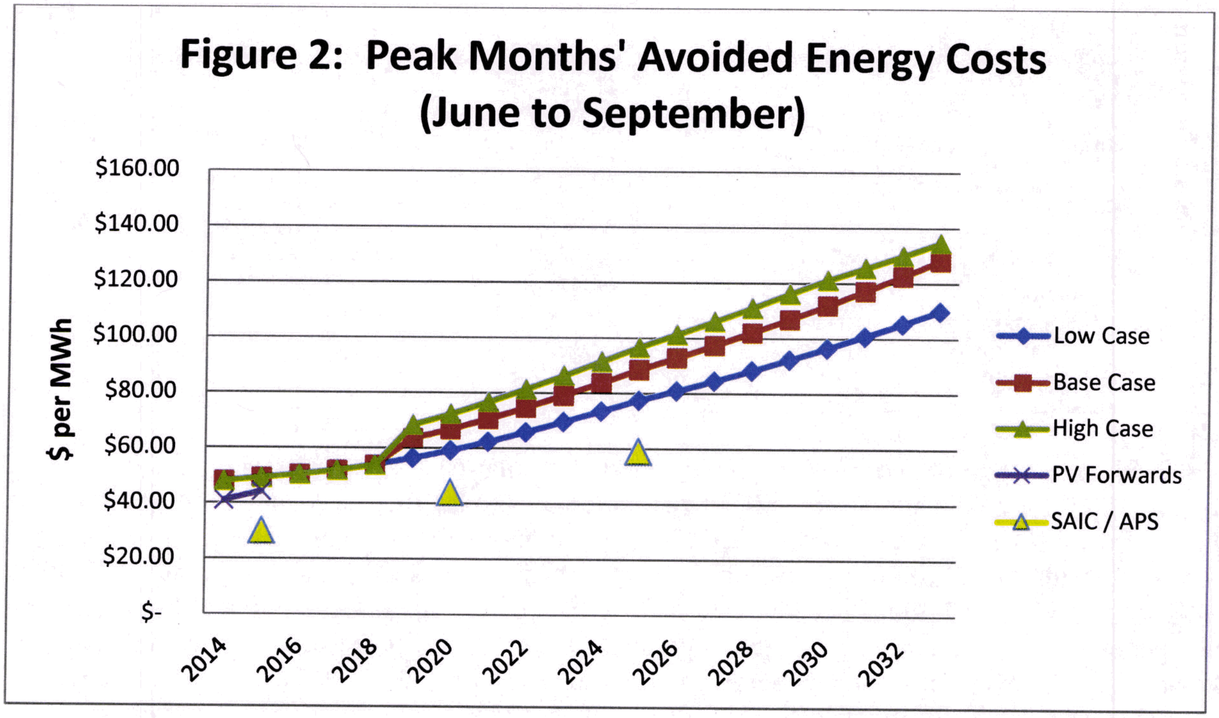
about $1.00 per MMBtu. We did not add these costs to the gas cost forecast for APS, although they appear to be a real, long-term cost of APS's gas procurement strategy.

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

[9] 2012 IRP, at Figure 15.

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

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



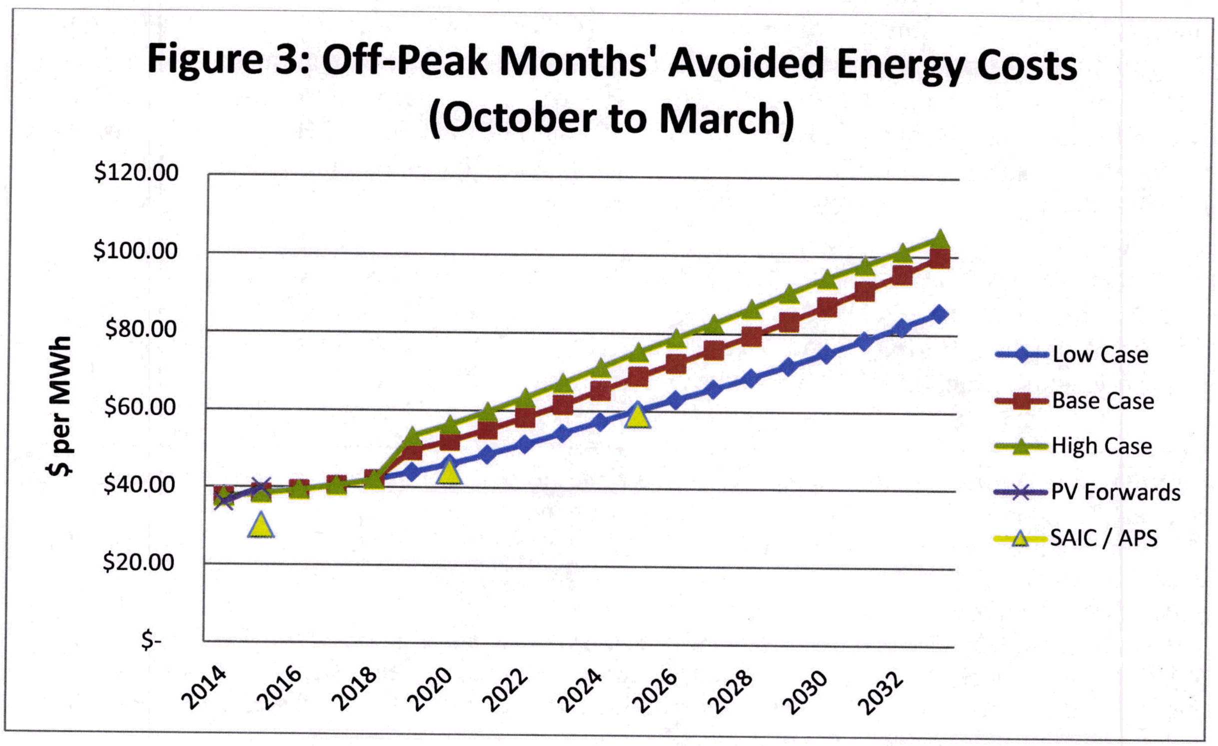


Table 2: *APS Avoided Energy Costs (including avoided line losses)*

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

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

Table 3: *SAIC / APS Avoided Energy Costs*

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

b. Generation Capacity

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

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

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

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

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

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

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[12] Beck Study at Tables 5-8 and 6-1.

[13] 2 012 IRP, Attachment D.3.

[14] SAIC April 11, at 66 and 73.

[15] 2012 IRP, at Attachments D.1(a)(1) and D.3.

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

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

c. Ancillary Services and Capacity Reserves

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

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

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

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

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

d. Transmission

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

Table 6: *Avoided Transmission Costs*

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

e. Distribution

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

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

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

Table 7: *Avoided Distribution Costs*

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

f. Environmental

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

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

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

Table 8: *Avoided Environmental Costs*

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

g. Avoided Renewables Costs

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

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

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

26 *Ibid*, at 141-143.

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

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

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

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

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

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[27] *Ibid.*, at 64.

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

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

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

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

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

3. Costs of Solar DG

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

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

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

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

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

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

33 ACC Docket No. E-01345A-12-0290. See APS response to Data Request Staff 1.

34 APS produced these estimates in 2012, so we assume they are in 2012 $.

35 Response to Data Request Staff 1.4.

36 Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

4. The Context for this Cost / Benefit Analysis

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

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

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

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

As distributed solar generation (DSG) and energy efficiency applications continue to become more accessible and affordable, we are likely to see increased adoption of technologies that manage and reduce customers' use of electricity from the grid.

Regulatory policies and electric rate design establish the critical framework for growth of DSG and related innovative 'behind-the-meter' technologies. Environment America, Environmental Law and Policy Center, Greenpeace, Pace Energy and Climate Center, Sierra Club, Southern Environmental Law Center, and Vote Solar support the following guiding principles to ensure fairness for all customers during this significant transition in our electricity infrastructure. Policymakers should consider only regulatory policies and electric rate design options that comport with these principles.[1]

1. Preserve Individual Customers' Rights to Self-determination:

Each customer can choose the amount of energy to purchase from the grid, the amount to self-produce and consume, and the amount to save through efficiency measures that reduce consumption. These rights include the installation of solar generation equipment at the customer's site, and interconnection to the utility grid without discrimination.[2] While any electrical devices connected to the grid must not compromise safety, reliability, or power quality, utilities do not have the right to restrict the decisions of customers regarding how to manage energy use on their own property. Most electric utilities operate under a regulatory compact where the electric utilities are required to do business within the confines of the public interest and are required to serve the needs of all customers within their territory in exchange for an exclusive monopoly franchise. Utilities are required to provide as much or as little electricity as the customer desires to purchase and consume.[3]

2. Capture the Full Range of DSG Benefits and Values:

Customer-sited solar generation offers many benefits to the electric utility system and by extension to non-solar customers. These include avoiding current variable utility costs such as fuel costs, near to long term demand-related utility costs such as building new power plants and other energy infrastructure including transmission and distribution investments, and societal costs including but not limited to health costs resulting from fossil fuel-generated air and water pollution. The values and benefits should be quantified, and solar customers should be adequately compensated for the value their solar energy is delivering to all customers

3. Promote Policies and Rates Favorable to Next Generation Distributed Technologies:

Regulatory policies and electric rate design should not inhibit the deployment of DSG, demand response, combined heat and power (e.g. fuel cells), storage or other innovative technologies that are currently available or will be available in the foreseeable future. Thus, when discussing changes to current rate structures, the ability of a customer to integrate DSG with storage to avoid fees and charges should be considered. Such a technology package could mitigate the effect of demand charges, but not increased fixed monthly customer charges. Tariffs and policies that create roadblocks to customer adoption of next generation technologies (e.g. customer-sited storage) should not be adopted.

4. Insist Upon Non-Discriminatory Rate Practices And Policies:

Utility rates should treat reductions in energy sales and utility revenues due to net metered solar and other DSG in a manner that is fully comparable to, and non-discriminatory relative to, reductions due to other consumer behaviors including energy efficiency and demand response. Any rate treatment not generally applied to all similarly situated customers must be cost-justified and seek to avoid unintended consequences.[4] Furthermore, any utility charges created specifically for the purpose of recovering embedded fixed costs from customers with DSG systems must be cost-based, and should only recover *net* fixed costs, after accounting for all benefits and offsetting cost reductions due to the distributed solar. Similarly, any utility *credits* created for the purpose of assuring that economic benefits resulting from the deployment of DSG systems are properly assigned back to the DSG customer(s) should only reflect *net* benefits, after accounting for all utility costs.

5. Due Process Is Essential:

Facilitating the deployment of distributed solar generation is critical for developing the energy structure of the future. Thus, it is of paramount importance that DSG rate policies be determined in regulatory forums guided by the rules of law where stakeholders have access to transparent and verifiable data. Claims of intra-class and inter-class cross-subsidies, and the comparative benefits of larger scale wholesale PV systems can be addressed most effectively where adequate data is available and transparent, and due process prevails. A transparent and data driven analysis that assures stakeholder due process rights are protected is likely to optimize the chances for an outcome that is best for customers. Utilities should not be able to undermine a regulatory proceeding by limiting data access or proposing an overly aggressive schedule that limits meaningful stakeholder participation.

6. Ensure that the Benefits of Rooftop Solar are Shared with Low-income Customers:

Within resource and grid planning processes, regulators must ensure that utilities effectively realize the present and future benefits that distributed solar provides in terms of freeing up capacity on the distribution and transmission system and reducing the need for infrastructure upgrades. These cost savings must be equally shared among all ratepayers, including low-income ratepayers, through thoughtful rate design.

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[1] These principles are designed for distributed solar generation but are generally applicable to other distributed energy resources as well.

[2] http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp

[3] Notable exceptions are made for very large, usually industrial, customers that require significant investments in infrastructure and sometimes generation. Such customers could have significant impacts on a utility were they to move or shut down.

[4] Example: Segregating net metered customers into their own rate class and designing rates that recover fixed costs through increased monthly customer charges and/or adding a demand charge can result in a much lower energy rate. This result can motivate high consumption customers, aka the wealthy, to install a minimal solar system (1-2 solar panels) to qualify for the rate and significantly reduce their utility bills, resulting in a far more dramatic reduction in revenue to the utility.

Solar Power

America's energy problems — from rising costs to global climate change — can be solved by a transition to clean energy. Reliable, homegrown solar energy is ready to be a large part of the solution. It is our fastest growing electricity source, but we have still just scratched the surface of our vast solar potential.

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Vote Solar is a non-profit organization working to foster economic opportunity, promote energy security and fight climate change by making solar a mainstream energy resource. We work at the state level all across the country to support the policies and programs needed to repower our grid with sunshine.

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We focus on making solar more accessible and more affordable to more Americans — and we could use your help. Get involved by joining Vote Solar. Sign up for email action alerts. Make a donation. Find us on Facebook. Follow us on Twitter. Most importantly: let your policymakers know that you support solar progress.

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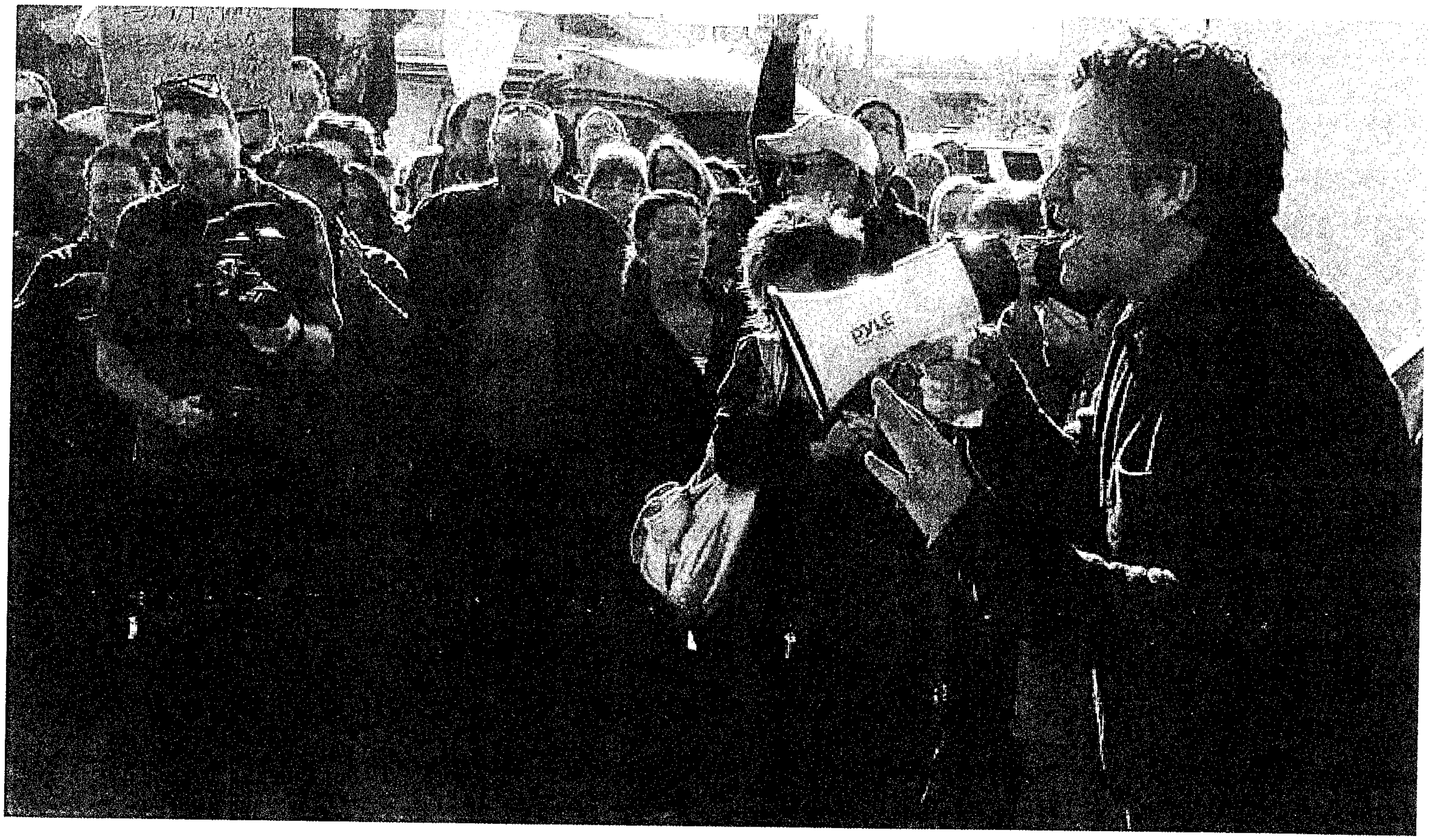
TECH SOLAR

The Other Side of the Solar Firestorm in Nevada

by Katie Fehrenbacher @katiefehren APRIL 12, 2016, 11:00 AM EDT



Actor Mark Ruffalo addresses a protest over new solar fees in Las Vegas.
Fortune, Katie Fehrenbacher

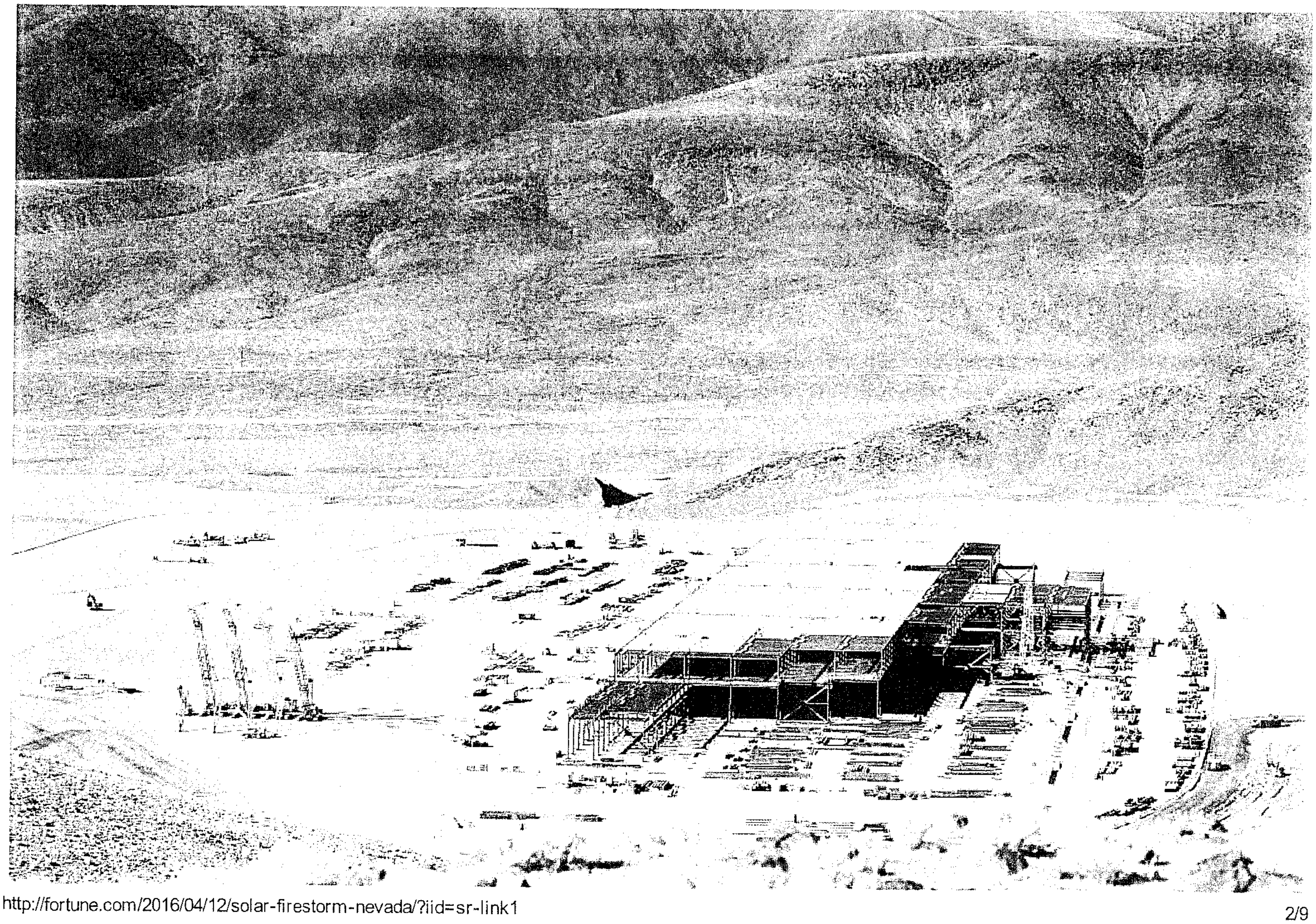
Here's the counter argument for changing Nevada's rooftop solar rates.

Earlier this year, celebrity actor Mark Ruffalo riled up a crowd of hundreds of protestors outside of an office building in sunny Las Vegas by shouting "let's make life uncomfortable for them. . . because they're wrong!" The "them" who Ruffalo was referring to included Nevada's Public Utilities Commission and its chairman, Paul Thomsen, who joined the energy regulator in October.

The issue that raised the protesters' ire was a rate hike for Nevada's solar customers that went into effect at the beginning of this year. Thousands of people who bought solar panels assuming they'd have to pay certain fees and earn a certain rate for the solar they produced are now getting a less attractive deal. The rate change has made the rooftop solar industry, Nevada's solar customers, and high profile protestors like Ruffalo furious.

A few months after that protest—which was partly organized by the solar company SolarCity ([illegible]) that's backed by billionaire Elon Musk—I find myself in Chairman Thomsen's office in Carson City, Nev., just outside of Reno. Thomsen might be new(ish) to the Public Utilities Commission, but he has a long background in energy in the state. He was formerly the governor's energy adviser and an executive at Nevada's geothermal giant, Ormat Technologies ([illegible]).

The night before our meeting, SolarCity had organized an event at Tesla's massive battery factory outside of Reno where SolarCity and Tesla (TSLA ▼ -2.56%) execs quietly lobbied Nevada's legislators about the future of solar in the state. The solar industry is trying to get the commission's decision reversed through a November ballot measure, a legislative special session, and a judicial review. Tesla CEO Musk and SolarCity CEO Lyndon Rive are cousins.



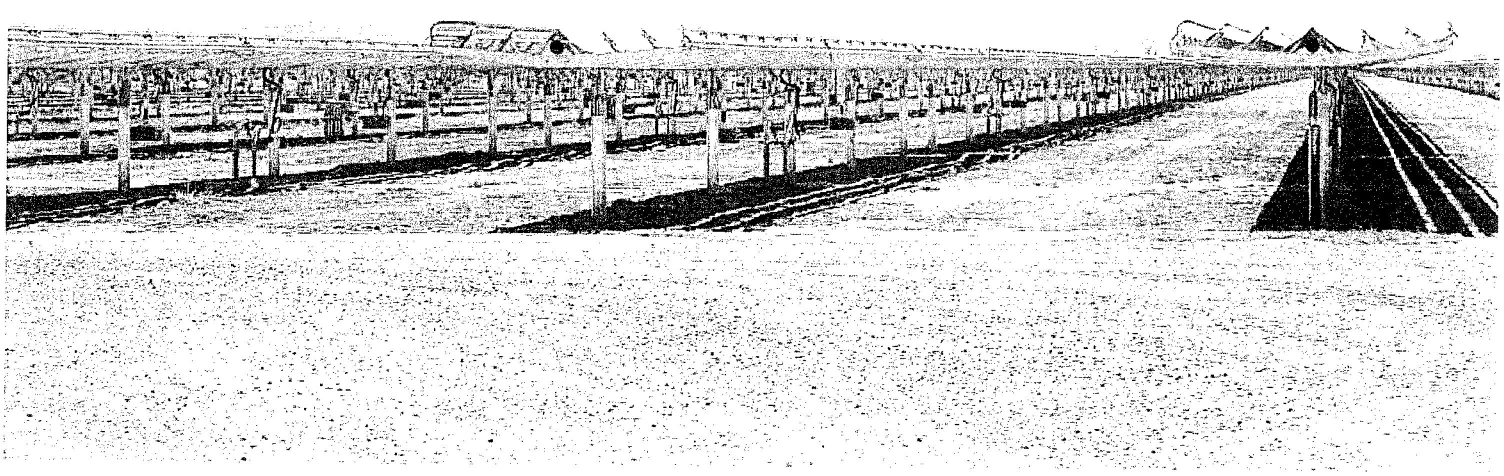
Construction of the Tesla Gigafactory outside Reno in February 2015.
Photograph by James Glover — Reuters

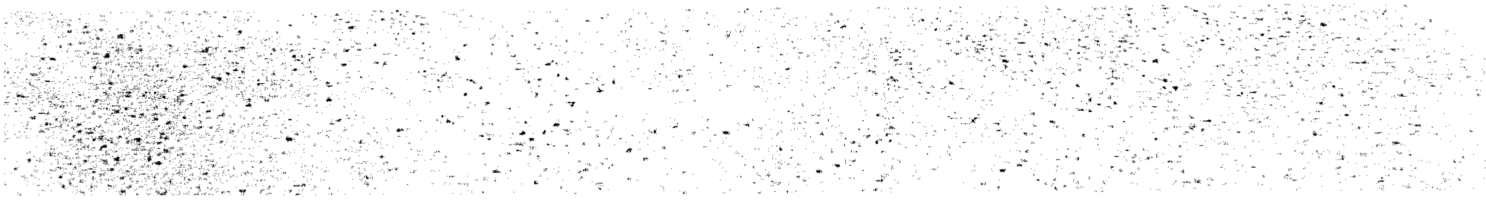
Thomsen joked about the flashy shindig, at which actor Leonardo DiCaprio made a brief appearance: "I think I missed my invite in the mail." Given that Thomsen helped lead the controversial solar rate hike that angers powerful figures like Rive, Musk, and celebrity activists, supporters of rooftop solar energy have made him a target.

But the solar rate hike is actually much more complicated than the inflammatory language that Ruffalo used when he accused the commission of "taking from the mouths of the people and giving it to a single monopoly utility." The rate boost is the result of the Nevada legislature's collective decision last year to start moving away from the solar subsidy called "net metering," whereby rooftop solar customers are paid inflated rates for the solar power they produce.

Utilities across the U.S., and the world as well, are trying to figure out how to manage and pay the extra cost for the influx of rooftop solar panels onto their power grids. When the solar industry was tiny and solar panels were expensive, progressive states like Nevada were eager to lend a hand with incentives like net metering to kickstart the nascent sector. But as more and more home owners have started to opt for solar deals—working with solar installers like SolarCity and Sunrun that offer deals with little or no upfront payments for homeowners—states are now rethinking whether the industry still needs that kind of handout.

Nevada has long been home to aggressive subsidies for clean power projects, including for both solar and geothermal power (by tapping into hot rocks deep underground). Eighteen years ago the state approved the solar net metering rule, and also something called a "renewable portfolio standard," which mandated that its utilities must get a quarter of their electricity from clean energy by 2025. The renewable portfolio standard, in particular, has led to an explosion in large sprawling solar panel farms built across the state that are contracting with companies like tech gorilla Apple (AAPL ▼ -0.49%) and data center giant Switch.





Apple's Fort Churchill solar farm in Yerington, Nev. became fully operational a few months ago.
Fortune/Katie Fehrenbacher

But as the number of rooftop solar customers started to grow in the state, and the cost of building large solar panel projects for utilities started to drop dramatically in comparison, Nevada's legislators began to look at the rooftop solar net metering subsidy. They asked the PUC to determine if non-solar customers (the vast majority of the utility customers in Nevada) were being charged unfairly in their monthly bill for the added costs and incentives for solar customers.

The commission determined that, indeed, the bulk of Nevadans were shouldering the burden of the solar customers, and it spent last year figuring out how to fix that. The extra costs come from the above market rates that solar customers are paid (in bill credits) for their energy.

The solar industry have contested these figures that the commission came up with at various times. But the result of the commission's findings are the controversial new rates introduced this year for solar customers.

In a concession to the controversy (and as a result of a request from the Nevada Bureau of Consumer Protection), the Public Utilities Commission partially tweaked its initial rate ruling and decided to give solar customers who already owned panels more time before the new rates are phased in. But they didn't budge on the general idea of eventually phasing out net metering.

PAC that would reverse the new hiked solar rates.

Nevada could be a potential bellwether for how states across the country deal with maturing solar net metering incentives. Many states and utilities offer such programs.

This year, however, California decided to maintain its attractive solar net metering rates until 2019. It was a big win for the solar industry because of that state's status as the nation's leader in solar power generation.

We sat down with Chairman Thomsen, to get his take on everything that happened. Below is an edited and condensed version of our conversation.

Fortune: **Did you expect such a vocal and critical reaction to the decision to phase out net metering?**

Thomsen: The net metering issue had been debated at the legislature in 2015, and they [the solar industry] had done a really heavy lobbying job then. I had no doubts that they would lobby or try to influence the Public Utilities Commission. From a political standpoint, lobbying works really well. But in hearings—where people follow the administrators act and take evidence and cross examine parties—I guess I was a little shocked to see that they had so much of a PR and media focus. As they well know, we have to examine the evidence that's in front of us.

To the extent that certain solar companies were bringing in bus loads of their employees to give public comment, I don't think we expected those theatrics. But it was a very well-known issue in the community and we expected some discussion. Frankly, we are happy to have it. This commission is very open, and all of the information we use is available. I greatly appreciate public participation.

The legislature passed the bill SB374 (in 2015) which said we want to reduce the subsidies for net metering and move to cost-based rates. The legislature sets the policy and we implement it. So years ago the legislature said 'do net metering,' and then later last year it said 'shift away from net metering.'

Up until the passage of that bill, so between 1997 and June 2015, there were 6,000 participants in Nevada's solar net metering program. After they passed that bill, 24,000 people signed up to participate in net metering between June 2015 and the end of the year. That's a 500% increase in customers.

A SolarCity employee installs a solar panel on the roof of a home in Los Angeles in May 2014.
Photograph by Patrick T. Fallon — Bloomberg/Getty Images

Why do you think that happened?

That's a great question to ask the solar companies. I don't know what the sales pitch was, but it must have been a good one to say, 'We don't know what the future rate will be, we don't know if you're grandfathered in, but we have such a compelling sales pitch that we're going to see a 500% increase before the end of the year.'

I'll tell you, we sat through 20 hours of public comment and the most moving parts of that were the seniors who said, 'I've taken out a second mortgage on my home to put on solar that starts at the retail rate and escalated 3% annually.' I was gobsmacked to hear that. That to me is a reprehensible sales tactic. I wish the commission had the ability to prevent that from happening.

In Nevada, in the same 2015 session, there was a proposal for a consumer protection bill regarding rooftop solar and it was killed by SolarCity and Sunrun. I really hope that the Nevada legislature continues to look at how we protect consumers if they need it.

We struggled with the decision, because if we grandfathered everybody in, we would have done the opposite of what the legislature had wanted, which was we wouldn't have reduced the subsidies. We would have increased them by 500%. We discussed at length in the hearing, which date do you arbitrarily pick [for grandfathering]? Is it before the bill is passed? Is it after we hit 235 megawatts, which is the cap that the legislature had set? Or is it the end of the year? Are we picking and choosing between one solar customer and another?

A SolarCity Corp. employee carries a solar panel in 2014. Photographer: Patrick T. Fallon/Bloomberg via Getty Images

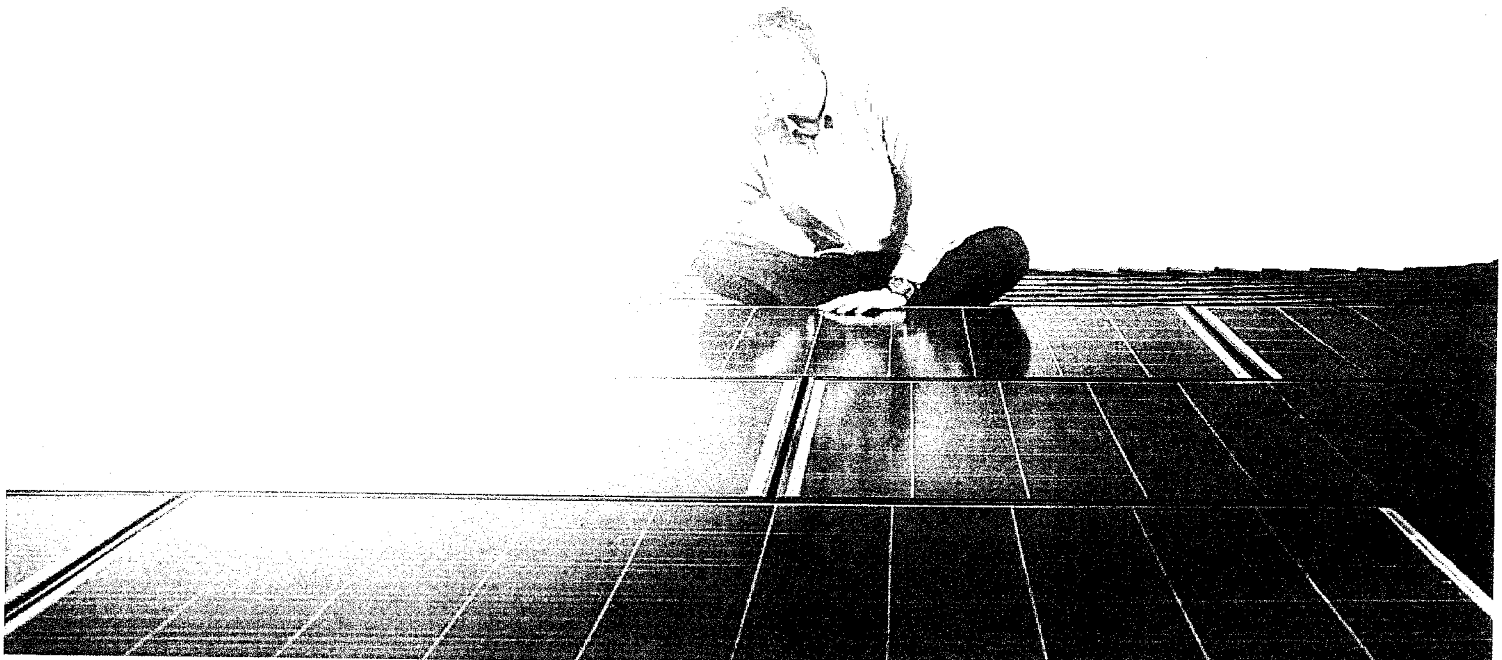
The subsidy we found was $16 million a year. So over 20 years that's an over $300 million subsidy, or cost shift that non-solar customers were providing to solar customers. Under our proposal, we've reduced that subsidy by two-thirds. So they're still receiving a $100 million subsidy, or cost shift, as we modify net metering going forward.

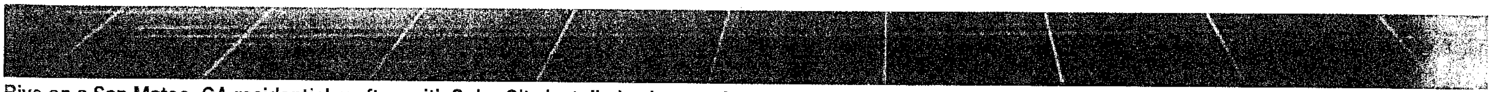
We were one of the first states to say there is empirical evidence that there is this cost shift. The [solar] industry didn't want to hear that. They can try to discredit all the studies they want but we have an open public case and all of the financial analysts and economists in this building that set rates said we found this cost shift and here's our proposal to mitigate it.

A lot of the discussion leading up to this was about 'is there a cost shift?' And I put that in the category of climate deniers– let's move on from that. The industry wanted us to make factual decisions based on Mark Ruffalo's testimony, and not the evidence in the case. For better or for worse, this commission makes decisions based on expert cross examination of the evidence of the case.

The solar industry really wants to have this debate in the media and outside of professional scrutiny. We had lots of data requests for information for them, which were not given to the commission. We put forward that we wanted to look at 11 variables to appropriately value the excess energy rate and they didn't provide quantifiable evidence for one single factor of those 11. Our staff did.

Now that we've come out with the general order I expect we'll see a discussion of those factors. And hopefully we can get that excess energy rate to move up taking into account those factors. But we need that evidence presented in front of the commission to do that.





Rive on a San Mateo, CA residential rooftop with Solar City installed solar panels.
Photograph by Gregg Segal for Fortune

Do you think that the effect on the rooftop solar industry will be as dire as SolarCity has claimed?

Yes and no. I'll be really candid. There are certain businesses and customers that solar is a good fit for. When you look at MGM, who put solar on the roof of their convention center and can avoid demand charges and can use power in the middle of the day, it's a brilliant application.

But a huge part of the growth potential for Sunrun and SolarCity is that person who is not home during the day, and their home is not consuming power during the day. Normally it would never make sense, because why would I want to put a generator on my roof, and produce power when I don't need it unless I have net metering.

That business model will have to be closely scrutinized, or there needs to be some innovation like coupling solar with battery storage or something to provide customers services they need. You will still see applications that made economic sense before net metering continue even with this new net metering rate. You're still getting to sell your excess power for something.

One of the main arguments from the solar industry is that the Nevada government and the commission is being influenced by utility NV Energy, which finds rooftop solar competitive. What's your response to that?

The only people who tried to influence the commission through ex parte communication was the solar industry. Coming from the governor's office of energy, the governor and I were accused of having close conversations. I'll tell you that the last day I met with him, which was Sept. 28, 2015, when I accepted this position, he told me in his office that the only thing I'll ever ask of you is to have the strength to do what's right. That's the last conversation I've had with him to this day.

For NV Energy, it was the same thing. After I left the Governor's Office of Energy, I have not had a single conversation with NV Energy outside of public hearings in this building. I don't even know if that's a good thing. We regulate them, so it would be nice to have more open conversations with them. But in this current environment of constant FOIA requests and calendar requests by groups like the Checks and Balances Project, they have just been completely isolationist from the commission.

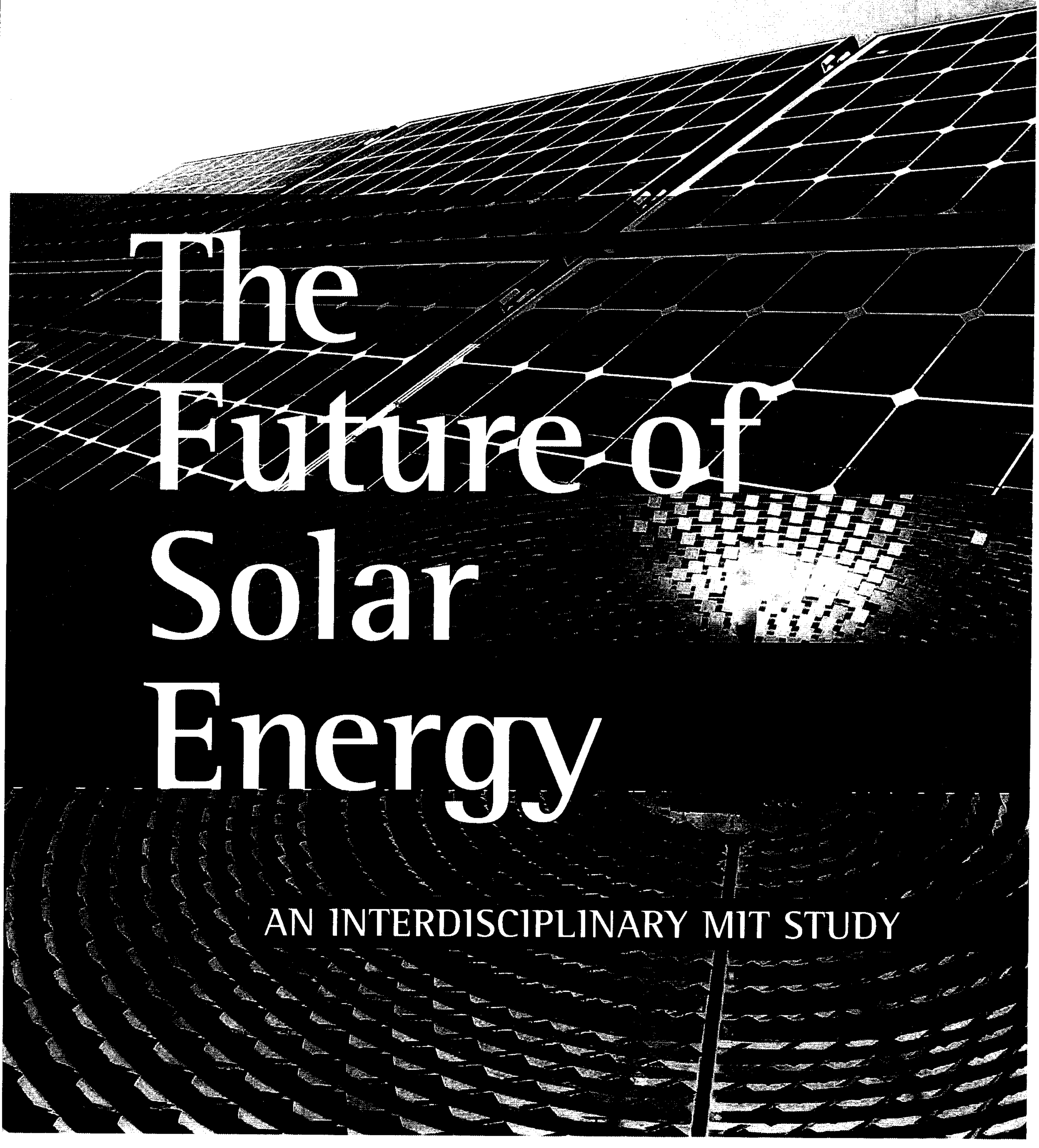
What I would say flippantly is it's easy to pick an enemy and paint the utility as this nefarious character who is trying to squash the rooftop solar industry. What I'd say to that is I think there are far greater forces at work than any relationship in Nevada. There are all-time record low gas prices, and Nevada is developing large-scale solar panel projects at record low prices—some of the lowest prices in the nation if not the world.

You say what's the difference between solar power coming off a rooftop that the utilities have to pay 11 cents for, versus the 4.5 cents they're paying for solar energy from large-scale solar panel projects? The delta has gotten so big. That's the debate.

The question that people bring up is since large-scale solar has gotten so cost effective, why hasn't rooftop solar? Lydon Rive says competition breeds innovation, and I would say subsidies do not breed innovation. And that big subsidy [net metering] that hasn't changed in close to 20 years has resulted in this very drastic over pricing of a product that now has to figure out how to compete. That's where we were.

I think we're all incredibly confident in this building that this rate design is going to be the future. That's probably why certain members of the solar sector are so fired up and concerned about what that looks like going forward. And while some are suing and fighting us in court, there are others who are innovating and putting out products that can compete in that fair market world.

7 Comments   Licensing



The Future of Solar Energy

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While the members of the advisory committee provided invaluable perspective and advice to the study group, individual members may have different views on one or more matters addressed in the report. They are not asked to individually or collectively endorse the report findings and recommendations.

Chapter 9 – Subsidizing Solar Technology Deployment

As noted at several points, we strongly favor a comprehensive policy to put a significant price on carbon dioxide (CO_2) emissions, either directly through a tax or indirectly through a cap-and-trade system. Such a regime provides an incentive to reduce CO_2 emissions from electricity generation and all other activities in the most cost-effective manner. Importantly, it provides across-the-board incentives for improving energy efficiency. In the presence of a cap on emissions, subsidies for the deployment of solar generation technologies would increase the cost of meeting the cap. In the presence of a carbon tax, such subsidies would reduce emissions but, by favoring one method of emissions reductions over others, would raise the cost per ton of emissions reductions. Deployment subsidies may nonetheless be justified even in the presence of a comprehensive carbon policy, however, if they contribute to advancing solar technology by producing knowledge that is widely shared. In contrast, subsidies to mature technologies, renewable and non-renewable, should be phased out once a comprehensive policy is in place.

In the absence of a comprehensive policy, subsidizing solar deployment may be justified as part of a second-best CO_2 reduction policy. In addition, ongoing deployment, even at modest scale, is likely to help reduce institutional and other barriers to a rapid scale-up of solar generation in the future while also stimulating industrial efforts to reduce costs and improve performance.

In any case, neither the United States nor most other nations have put a significant price on CO_2 emissions. Instead, governments in many countries have adopted a variety of "market pull" policies to promote the deployment and use of solar generation technologies.[i] It is important to recognize, though, that solar technologies are not unique in this regard. The energy sectors in most nations are shaped by subsidies to multiple energy sources. In the United States, for instance, the U.S. Energy Information Administration (EIA) found that direct federal subsidies to solar energy in fiscal year 2010 were less than those to coal, natural gas and petroleum liquids, nuclear, and wind, and comparable to subsidies for biomass.[3]

In the absence of a comprehensive policy, subsidizing solar deployment may be justified as part of a second-best CO_2 reduction policy.

[i] A detailed discussion and evaluation of alternative technology-specific policy approaches is available in Batlle, Pérez-Arriaga, and Zambrano-Barragán.[1] For an analysis that considers the impacts of alternative policies on choices among renewable technologies, with implications for CO_2 emissions, see Fell, Linn, and Munnings.[2]

While they differ in many respects, most of these policies to promote solar deployment can be usefully grouped into four main types: *price-based, output-based, investment-based,* and *indirect.*[ii] In almost all cases, solar generation of electricity is either treated the same as other renewable generation technologies or, more commonly, is given more favorable treatment. Such policies may be part of a second-best strategy to reduce CO_2 emissions (except in the European Union, where CO_2 emissions are capped) and perhaps to reduce the costs of solar electricity,[9] but they are often described as advancing other objectives as well. Section 9.1 discusses some of these additional objectives.

Our main concern here is with the efficiency of solar deployment subsidies, i.e., with the value of electricity produced per dollar of subsidy spending.

Our main concern here is with the efficiency of solar deployment subsidies, i.e., with the value of electricity produced per dollar of subsidy spending. Sections 9.2–9.5 discuss each of the four main types of renewables policies listed above. Section 9.6 then describes what is known and (mostly) not known about the effectiveness of these policies in the United States, and Section 9.7 provides our recommendations for making U.S. solar deployment subsidies more efficient. We believe there is significant room for improvement.

9.1 OBJECTIVES OF DEPLOYMENT SUPPORT

Some have argued that deployment of solar generating facilities should be subsidized in order to build a competitive solar manufacturing industry in the United States, thus positioning domestic suppliers to take advantage of high expected growth in global demand. The main problem with this argument is that subsidizing purchases of some product in the United States or any other nation does not guarantee that local suppliers will meet that demand, since nations' World Trade Organization obligations greatly restrict their ability to protect domestic suppliers with tariffs or quotas.[10] For example, as a consequence of generous subsidies, particularly in Germany, the European Union (EU) accounted for over 53% of new photovoltaic (PV) module installations in 2012, but European firms accounted for only 11% of global module production.[11] In the complex global PV supply chain, technological knowledge readily travels across national borders, and the design and manufacture of these tradable products tend to be performed in the most cost-effective locations.[12]

Moreover, this argument rests on the assumption that even though the U.S. solar industry would be competitive in global markets with adequate investment, capital markets will not provide the necessary funding. But it has proven possible to raise large amounts of money for risky, long-lived investments in a wide variety of sectors — including projects that produce and use fossil fuels as well as others involving new technologies. We are aware of no evidence indicating that solar or other renewable technologies suffer any *special* handicaps that relate to the capital markets. If the global solar market has great growth prospects, it will attract capital — though not necessarily from the United States or for investment in the United States.

[ii] Unless otherwise stated, information about U.S. policies in this chapter has been drawn from the Database of State Incentives for Renewables & Efficiency (DSIRE), the standard reference for current U.S. federal, state, and local policies to support energy efficiency and renewable energy.[4] Detailed information on all energy-related federal subsidies in fiscal year 2010 is from the U.S. Department of Energy's Energy Information Administration (EIA).[5] Information on support policies in the 28 EU nations and five affiliated nations is from LEGAL.[6] The standard reference for support policies globally is from the Renewable Energy Policy Network for the 21st Century (REN21), updated annually.[7] While we focus on support of solar energy here, it is worth noting that other energy technologies are also subsidized. In fiscal 2010, for instance, solar energy received only 8.2% of U.S. federal subsidies and support for electricity production.[8]

To be clear, it may be desirable to subsidize some domestic manufacturing to aid the process of advancing solar technology. Manufacturing cost is a critical attribute of any new solar technology, and it is often hard to judge manufacturing cost without actually doing manufacturing. But, as we discuss further in Chapter 10, this argument calls for selective support of firms working with promising new technologies rather than broad support of solar manufacturing.

Finally, since global greenhouse gas emissions drive climate change, widespread international adoption of new non-emitting technologies has global benefits and generally benefits the United States as well. Like all trade barriers, impediments to the flow of intellectual property or restrictions on the trade of products in the solar value chain reduce global economic efficiency. In this case, such barriers can only raise the cost to the world as a whole of reducing CO_2 emissions via increased use of solar energy.

FINDING

Barriers to the diffusion of solar technology or to international trade in products in the solar value chain will make it more expensive to slow climate change by reducing global CO_2 emissions.

It is sometimes argued that solar and other renewable energy technologies should be supported by government subsidies because they create more desirable jobs in the domestic economy than alternative energy technologies. There are at least three problems with this position. First, we are unaware of any rigorous studies showing that renewable technologies — particularly solar and wind — in fact have higher labor content, properly measured, per unit of output than relevant alternatives. Second, the notion that labor-intensive technologies deserve special support ignores the fact that labor-saving innovations have been major drivers of economic progress. The mechanization of agriculture destroyed many jobs, for instance, but it helped make large-scale industrialization possible. The main long-term effect of subsidizing labor-intensive technologies is to raise the cost of goods and services provided by the private sector. Finally, if the government were to seek to create jobs in the short term by subsidizing particular industries, it is not evident that choosing renewable energy, rather than, say, infrastructure construction or public education, would be the most cost-effective choice.

Some also believe that the strong public support expressed for solar energy justifies the use of public funds to promote its use even absent a market failure rationale. But it is easy for citizens to be in favor of government spending on renewably-generated programs when this spending is not linked to personal costs or to reductions in other programs they also support. Similarly, while people often respond positively to surveys asking if they are willing to pay non-trivial amounts for renewably-generated electricity, it is well known that the answers to hypothetical questions of this sort overstate real willingness to pay.[13] Thus, even though "green power" was available to about half of U.S. electricity customers in 2012, voluntary purchases of green power accounted for only 1.3% of total U.S. electricity sales in that year, with green power sales to residential customers accounting for only 0.3%.[14]

Finally, adding more solar generation would certainly increase supply diversity in the U.S. electric power system, which is becoming increasingly dependent on natural gas. But adding almost any grid-scale, non-gas technology would also serve this objective, and adding wind, biomass, or nuclear capacity might do so at a lower cost.

9.2 PRICE-BASED POLICIES

Though the United States has not made much use of this policy instrument, many nations have supported solar generation via *feed-in tariffs*, which entitle favored generators to be compensated for electricity delivered to the grid at predetermined, above-market rates for a fixed period of time.[iii] The cost of this subsidy is generally added to the retail cost of electricity. Within nations that employ such policies, differences in the regional penetration of renewable generation — reflecting, for example, differences in insolation — would lead to differences in the cost of electricity. European feed-in tariff schemes generally include systems for equalizing their impacts on electricity prices among sub-national regions.[16] Since the costs of renewable generation are uncertain, change over time, and vary from project to project, the quantitative response to any particular tariff level is uncertain. In recent years, several of these schemes have limited the risk of excessive response by either limiting total spending in any year or by reducing the tariff automatically when quantity milestones are passed.

Though the United States has not made much use of this policy instrument, many nations have supported solar generation via feed-in tariffs.

The first generally recognized use of feed-in tariffs was in the United States, under the Public Utility Regulatory Policy Act of 1978 (PURPA). PURPA required vertically integrated electric utilities to purchase power from facilities defined as "qualified" at prices equal to the utilities' "long-run avoided costs." Avoided costs were to be determined by state regulators who were sometimes overgenerous, notably in California.[iv] This system was largely dismantled by the early 1990s, as generous feed-in tariffs became increasingly unsupportable in the face of declining electricity prices.[18]

In 1991, Germany became the first country to adopt feed-in tariffs explicitly aimed at promoting solar and other renewable technologies; Denmark followed suit the next year. Feed-in tariffs have proven a very popular policy abroad, and in 2008, the EU concluded that "*well-adapted* feed-in tariff regimes are generally the most efficient and effective support schemes for promoting renewable energy."[v] Feed-in tariffs played a major role in boosting solar energy in Germany, Spain, and Italy — EU countries that have led recent growth in the global solar energy market. As of early 2013, 71 countries and 28 states or provinces employed feed-in tariffs, including 17 EU member states.[20] In contrast, this policy mechanism is not widely used in the United States.[vi]

Since solar power is at present one of the more expensive renewable generation options in most regions, feed-in tariffs that apply equally to solar and other renewable technologies could be expected to do very little to encourage solar generation relative to other renewables. Most feed-in tariffs in Europe provide higher rates for more expensive renewable technologies, with an eye to equalizing expected profitability — in these cases, solar generation typically receives the highest rate.[16] The

[iii] For a general discussion of feed-in tariffs and their interaction with output quotas see Cory, Couture, and Kreycik.[15]

[iv] For a useful general discussion of feed-in tariffs, see Lesser and Su.[17]

[v] Emphasis in original source — Commission of the European Communities.[19]

[vi] Rhode Island, California, and Washington have feed-in tariffs for certain small generators. See also Couture and Cory.[21]

German feed-in tariff has been both generous and tilted toward solar, with the result that Germany, not a particularly sunny nation, had 45% of EU solar capacity and 26% of world capacity in 2013.[22]

One very important and desirable property of feed-in tariffs is that they preserve strong incentives for both investment efficiency and operating efficiency. With the price of output fixed, every dollar of investment cost reduction translates into a dollar of profit, and every additional kilowatt-hour (kWh) produced adds to profit.

From the investors' point of view, fixing the output price removes all risk associated with the supply and demand for electricity. This may be a large part of the reason for the popularity of feed-in tariffs and their potency per dollar of subsidy spending.[vii] But the level of spending understates the true subsidy involved, since shifting risk from renewable generators to other parties in the market for electricity is also a subsidy, albeit one that is essentially invisible.[viii]

An important risk associated with feed-in tariffs is that the quantity of electricity supplied in response to any given level of subsidy is uncertain. With some technologies this would not be a significant problem because it often takes years to build a new generating facility, a long time relative to the time required to change support policies or to adapt the grid to handle new power flows. But PV, particularly residential PV, can be deployed much more rapidly. In 2013, for instance, PV capacity in China nearly tripled, in Japan it more than doubled, and in the United Kingdom it increased by 83%.[24] Between 2011 and the end of 2013, PV capacity in Hawaii increased by 283%, mainly through the installation of distributed PV. By the end of 2013 more than one in nine Hawaiian homes had rooftop solar installed.[25,26] Under the German feed-in tariff regime, deployment targets have sometimes been substantially exceeded despite reductions in support over time. The sensible approach eventually adopted in Germany was to reduce the level of subsidy automatically when deployment targets were met.[ix]

Feed-in tariff schemes generally guarantee the same revenue per kWh regardless of when that power is generated.

Finally, feed-in tariff schemes generally guarantee the same revenue per kWh regardless of when that power is generated. The wholesale spot price of electricity (or system marginal cost in a vertically integrated system in which a single firm controls generation, distribution, and retail sales) often varies dramatically depending on weather, time of day, and other factors. Feed-in tariffs that do not vary with the wholesale price therefore reduce the subsidy (the difference between the feed-in tariff and the market price) when electricity is most valuable, thus distorting incentives regarding the timing of production. Since solar generators that are in operation today have little or no control over the time-shape of their output, this may be a small effect for these technologies, though the timing of planned maintenance

An important risk associated with feed-in tariffs is that the quantity of electricity supplied in response to any given level of subsidy is uncertain.

[vii]Of course, investors still bear the risks related to the performance of the facility involved.[21]

[viii]For a simple model of such risk-shifting, see Schmalensee.[23]

[ix]On the German experience, see Weiss.[27]

outages is generally under the control of the unit's operators.[x] For new systems, however, subsidies that vary with the wholesale price will provide incentives to face PV panels west instead of south.[xi] West-facing panels produce less total electric energy over time compared to south-facing panels, but they tend to produce more during the late afternoon, when demand and prices are higher. And such subsidies would affect both the amount of storage built into new concentrated solar power (CSP) plants and the operation of those plants.

The use of tax credits instead of direct payments reduces the impact of the subsidy per dollar of cost to the government.

Output subsidy mechanisms (also known as premium tariffs or feed-in premiums) differ from feed-in tariffs in that they provide renewable electricity generators a predetermined per-kWh subsidy in addition to whatever revenues they earn from the sale of electricity, rather than a predetermined total price (amount of revenue) per kWh. The subsidy may vary (positively or negatively) with the wholesale price. As with feed-in-tariffs, the cost of the subsidy is generally added to retail electric bills. As with feed-in tariffs generally, this approach does not guarantee a certain level of renewable energy production. It has been notably less popular in Europe than the feed-in tariff.[29]

Beginning in 1993, with lapses and modifications in the intervening years, the U.S. government has provided corporate income tax credits for each kWh produced by certain renewable technologies. Solar-powered generating units were only eligible if placed in service during 2005. Some states, including Arizona and Florida, offer state tax credits for renewable generation.[xii] As we note in Chapters 4 and 5, the use of tax credits instead of direct payments reduces the impact of the subsidy per dollar of cost to the government. The problem is that to take advantage of the tax credit, a firm must have income at least equal to the credit, or must find a partner that does, and incur the significant cost of tax equity financing to obtain some of the benefits. The need to ensure that the tax credit can be used adds a constraint to the project finance problem that reduces the per-dollar impact of this form of subsidy by half, according to one source.[30] That is, spending a certain number of dollars on cash subsidies for renewable generation would induce more renewable generation than a program of tax credits that costs the government the same number of dollars in lost revenue.

The main advantage of an output subsidy as compared to a flat feed-in tariff is that it provides better incentives for producing electricity when the electricity is most valuable.[xiii] In addition, under an output

[x] It is worth noting that in the absence of a feed-in tariff, if a firm owns conventional dispatchable generation, the more solar generation it also owns, the greater the potential profit it can obtain (via higher revenues for solar generation) by restricting conventional generation to raise market prices. If solar generators receive a (fixed) feed-in tariff, this potential profit is eliminated, and thus so is the incentive to exercise market power by restricting output from conventional plants. On the other hand, this potential problem can also be mitigated, at least in principle, by limiting the market shares of conventional generators or by restricting large conventional generators' ownership of solar facilities.

[xi] California recently adopted an explicit incentive for west-facing solar systems.[28]

[xii] All information in this paragraph is from the DSIRE website.[4] As we note below, the federal subsidy for solar did not disappear in 2006: it became an investment tax credit.

[xiii] The system in the Netherlands, in which the subsidy is proportional to the market price, is particularly effective in this regard.[16] In contrast, the system in Spain reduces the premium when the market price is high, presumably on the grounds that a high market price provides sufficient incentive.[31]

subsidy, electricity-market risk is borne by subsidized generators as well as by other market participants, and spreading risk generally increases economic efficiency. While prospective investors in favored technologies would rather not bear risk, it is socially efficient to compensate them for doing so by increasing the subsidy.[xiv]

FINDING:

Among price-based subsidies, direct payments to renewable generators are more efficient than tax credits, and output subsidies provide better incentives for producing power when it is most valuable than flat feed-in tariffs. Because PV can be deployed very rapidly, the deployment response to price-based subsidies may depart rapidly and substantially from expectations.

9.3 OUTPUT-BASED POLICIES

Outside the United States, output quotas for renewable energy are not as popular as feed-in tariffs. As of early 2013, such policies were in place in only 22 countries at the national level.[20] Output quotas outside the United States are usually implemented via "tradable green certificates." Solar and other renewable generators sell power at the market price and then are able also to sell, in effect, a 1-megawatt-hour (MWh) green certificate for each MWh of electricity they have sold. Distribution utilities or others obliged to source at least a certain percentage of their electricity consumption from renewables can show that they have done so by purchasing an appropriate number of green certificates (often via long-term contracts that also involve purchasing power) and surrendering these certificates to the authorities. In recent years, it has become more popular internationally to have a government agency procure renewable generating capacity centrally; by early 2013, 43 countries, not all of which had output quotas, were using some variant of such centralized procurement.[xv]

Outside the United States, output quotas for renewable energy are not as popular as feed-in tariffs.

The trading feature assures that costs are minimized within the jurisdiction involved, as the cheapest allowable renewable technologies are used to produce green certificates. Since solar is generally one of the most expensive renewable technologies, output quota policies without an explicit tilt toward solar are unlikely to do much to encourage solar generation. It is also important to note that, just as the quantity of renewable generation supplied in response to a fixed feed-in tariff is uncertain, the price of tradable green certificates is also uncertain under a fixed output quota.

Since solar is generally one of the most expensive renewable technologies, output quota policies without an explicit tilt toward solar are unlikely to do much to encourage solar generation.

In the United States, output quotas are universally known as *renewable portfolio standards* (RPSs). Iowa enacted the first RPS in 1983, and such programs are now in force in 29 states and the District of Columbia.[xvi] Many RPS programs treat renewable energy technologies differently. Illinois, for instance, requires that 75% of renewable generation come from wind.

[xiv] A disadvantage is that at high levels of penetration, the market power issue raised in Footnote x above could be important.[1]

[xv] For a discussion of the use of auctions in South America, where they are the main support method, see Battle and Baroso.[32, 33]

[xvi] For a general discussion of RPS programs, see Schmalensee.[23]

As of September 2013, 17 of the 30 state-level RPS programs in the United States included provisions that explicitly favored solar power or distributed generation (which in recent years has been predominantly PV).[34] Several of these programs give extra credit for solar or distributed generation, while Texas gives double credit for non-wind renewable generation. The others have minimum solar requirements of various sorts.

It is not obvious why the output quota or RPS approach is so popular in the United States when experience internationally has made it so unpopular elsewhere.

RPS obligations generally fall on entities that sell electricity to end users. In almost all cases, compliance is demonstrated by retiring "renewable energy certificates" (RECs) that function like the "tradable green certificates" discussed just above.[xvii] Many RECs are sold as a bundle with electricity in long-term deals, so spot markets for RECs are generally thin, with few transactions and large spreads between the price bid and the price asked. In states with explicit requirements for solar generation, the requirement is generally met by retiring solar RECs, which are produced when electricity is generated by qualified solar facilities. Ideally, this trading mechanism would enable renewable electricity to be generated and used where it is relatively most efficient, with utilities elsewhere helping to bear the cost. And, since the potential for renewable generation varies widely among states, nationwide trading of RECs could be an important way of reducing the cost to the nation of meeting a given quantity goal for overall renewable electricity production.

At present, however, only 16 of the 30 U.S. RPS programs permit the use of RECs from facilities that do not deliver to in-state customers to satisfy RPS requirements, and only two programs appear to accept RECs from renewable sources anywhere in the United States.[xviii] Restrictions on trading appear in most cases to be motivated by a desire to promote local economic development. While a national RPS program could, in principle, reduce overall national costs, a national renewable portfolio requirement has never been enacted in the United States, and most proposals for such a policy contemplate leaving the states free to enact more stringent standards.[xix]

It is not obvious why the output quota or RPS approach is so popular in the United States when experience internationally has made it so unpopular elsewhere.[xx] One possibly relevant factor is that the costs of RPS programs are generally built into long-term contracts between utilities and generators and thus are much less visible than the explicit subsidies paid under feed-in-tariff or output subsidy schemes. There is certainly no general economic reason to favor a quantity-oriented

[xvii] See, for instance, Cory and Swezey.[35] New York, Iowa, and Hawaii do not use RECs.

[xviii] See Schmalensee.[23] It is also worth noting that only two RPS programs permit RECs to be banked for an unlimited period; most limit their lives to two or three years. It is not clear what purpose these limits are intended to serve.

[xix] An additional output-based policy deserves mention. The U.S. military, the world's largest energy consumer, has programs in place to meet a statutory mandate of 25% of total facility energy consumption from renewable sources by 2025.[36] While this is ambitious on several levels, the military plans to install only 1.1 gigawatts (GW) of PV capacity between 2012 and 2017, about one-third as much capacity as was installed in the United States in 2012 alone.[37]

[xx] For an examination of the effectiveness of U.S. RPS programs, see Carley.[38]

approach like RPS over the price-oriented approaches generally used internationally; moreover, the quantity approach does not appear to be administratively simpler. Indeed, it is hard to imagine a more complex regime than the multiplicity of different state programs now in place in the United States.

FINDING:

A nationwide RPS program that permitted unlimited interstate trading would have lower costs for any given level of deployment of solar or other renewable generation than the multiple, diverse state programs now in place.

9.4 INVESTMENT-BASED POLICIES

The promotional mechanisms discussed so far all directly reward the production of electricity using solar energy. Policies that reward production are generally superior in terms of return per dollar spent to policies that subsidize investment in solar generation. They provide stronger incentives to reduce investment cost, to locate in areas with high insolation, and to maintain and operate generating units efficiently. With an investment subsidy, a dollar of investment cost overrun reduces enterprise profit by less than a dollar because it also increases the government's subsidy. Moreover, incentives to produce power are less than when production is subsidized or required. Finally, when a facility is owned by its builder rather than purchased from a third party, the fair market value must be estimated in order to compute the subsidy. As discussed in Chapter 4, that estimation is subject to all the difficulties that arise in transfer pricing disputes in tax matters.[xxi]

Policies that reward production are generally superior in terms of return per dollar spent to policies that subsidize investment in solar generation.

Nonetheless, at least 25 of the 30 countries that are part of the Organization for Economic Co-operation and Development (OECD) have used one or more forms of investment subsidy, generally along with other incentives or policies, to promote solar generation.[40] In some cases, these subsidies take the form of grants or other payments from the government, in which case they may be subject to budgetary pressure. In other cases, these subsidies are delivered as tax reductions, which restrict the investment to those entities that can take advantage of the reduction directly or, more commonly, by means of the tax equity market. In either case, the cost of the subsidy is borne by individuals in their roles as taxpayers rather than as electricity consumers. Electricity consumers generally bear the cost of price-based or output-based subsidies through higher retail electricity prices. Higher retail prices provide incentives to reduce electricity consumption across the board, thus further reducing fossil fuel use and CO_2 emissions. This incentive is absent when taxpayers bear the cost of investment subsidies.[xxii]

[xxi] A recent study estimates that prices reported for tax credit purposes for third-party-owned systems are inflated about 10% on average.[39]

[xxii] Fell et al., provide a quantitative analysis of this difference.[2]

Making REITs or MLPs available to solar developers would allow the government to replace the current investment tax credit entirely or in part and lower the cost of the subsidy to taxpayers without reducing its value to developers.

As discussed in Chapter 5, the U.S. federal government provides two significant investment-based subsidies for solar generation: five-year accelerated depreciation (since 1986) and a 30% investment tax credit (since 2006).[xxiii] A number of observers have pointed to the stability of these policies as encouraging investment in the solar industry. In fiscal year 2010, the investment tax credit alone cost the federal government $616 million.[xxiv] Some solar industry stakeholders and supporters have argued that the federal government should increase investment subsidies by making solar generation projects eligible to be owned by real estate investment trusts (REITs) or, as is the case with pipelines and many other fossil energy projects, master limited partnerships (MLPs). These vehicles would essentially enable solar projects to avoid the corporate income tax and would also eliminate the need for most projects to go through the tax equity market.[xxv] Because of this latter feature, making REITs or MLPs available to solar developers would allow the government to replace the current investment tax credit entirely or in part and lower the cost of the subsidy to taxpayers without reducing its value to developers.[xxvi]

In addition, all U.S. states now provide some subsidy for investments in solar electric generation. These incentives involve various mixtures of grants (direct or through local utilities), low-interest loan programs, reductions in state sales or income taxes, reductions in local property taxes, and tax credits of various sorts. In addition to a production tax credit, for instance, Arizona provides an investment tax credit, exempts solar generating equipment from the state sales tax, and exempts residential solar facilities from local property tax. Cities also provide a variety of investment-based subsidies. For instance, San Francisco and Chicago give cash grants for solar installations; Honolulu offers zero-interest loans; and New York City offers property tax reductions proportional to the costs of PV installations.

[xxiii] Policies were and are in place to provide grants and subsidized financing for entities such as tribes and local governments that do not pay income tax.[37] Also, the American Recovery and Reinvestment Act of 2009, as amended, made it possible for business taxpayers to receive a grant instead of the investment tax credit for solar facilities begun before the end of 2012.[41] By the end of October 2013, $5.2 billion of such grants had been paid.[42] The investment tax credit for residential facilities is scheduled to phase out at the end of 2016, when the credit for commercial facilities is scheduled to fall to 10%.

[xxiv] The federal government has also guaranteed loans taken out to finance the construction of selected PV production facilities, thus providing investment subsidies for those facilities.[43] The EIA has estimated that in fiscal year 2010, federal loan guarantees for solar production facilities provided a subsidy of $173 million.[44] Since the main aim of these loan guarantees seems to have been to advance technology, they are discussed in Chapter 10.

[xxv] For a useful discussion, see Feldman and Settle.[45]

[xxvi] A related financing vehicle, the so-called yield co (YC) has recently become popular.[46] Classically, YCs own operating generating plants — solar and otherwise — that have sold their power under long-term contracts, and they pay most of the resulting cash flow directly to their shareholders. They thus produce bond-like returns for shareholders, but offer somewhat higher returns than can easily be obtained in the bond market. In addition, if most of a YC's plants are relatively new, depreciation will generally exceed revenue so that the YC will have no taxable earnings. In that case, payments to shareholders are treated as returns *of* capital and are accordingly not taxed at that level either. Thus, YCs can be a vehicle for deferring taxes for some years.

FINDING:

Investment-based subsidies, particularly those that take the form of reductions in profit taxes, are less effective per dollar of government cost at stimulating solar generation and displacing fossil fuels than price-based or output-based subsidies.

9.5 INDIRECT POLICIES

Beginning with Massachusetts and Wisconsin in 1982, 43 U.S. states plus the District of Columbia now subsidize the output from small, distributed renewable (including solar) generators by means of *net metering*; internationally, 43 other countries use this mechanism.[xxvii] The federal Energy Policy Act of 2005 requires all utilities to make net metering available to those customers who request it. Net metering compensates these generators at the retail price for electricity they supply to the grid, not at the wholesale price received by grid-scale generators. A large fraction of the cost of running a distribution system is fixed, independent of load, but much or all of this fixed cost is generally recovered from retail customers through a per-kWh distribution charge. When a residential customer installs a rooftop PV generator, that customer's distribution charge payments are reduced. But there is no corresponding reduction in the distribution utility's distribution system costs. As noted in Chapter 7, the subsidy is the corresponding reduction in the utility's revenues, which may be made up by increasing the retail price paid by all customers.

For instance, in Boston in August 2014, the local distribution company, NSTAR, generally charged 9.8 ¢/kWh for electricity, reflecting average wholesale market prices, and 8.9 ¢/kWh to deliver that electricity. But electricity supplied by a rooftop PV array in Boston mainly saves NSTAR only its wholesale electricity cost; the delivery charge serves to cover NSTAR's costs to own and operate the distribution system.[xxviii] Therefore, net metering in Massachusetts involves a substantial subsidy to distributed generation — as it does elsewhere.[xxix] For at least some California retail customers, for instance, the value of the net metering subsidy apparently exceeds the value of the federal investment tax credit.[49]

Moreover, because the distribution utility pays this subsidy, it has strong incentives to make it hard to install distributed generation. So-called decoupling arrangements in some states deal with this problem by automatically increasing per-kWh distribution charges so as to maintain utility profits. But this shifts the burden of covering distribution costs from utility shareholders to those customers who do not or cannot install distributed generation, a group that is likely to be less affluent than those who benefit from net metering.[49] Even at the current relatively low penetration of residential solar, this cost shifting has become controversial in many states. It seems unlikely that the much larger cost shifts that would be induced by substantial penetration of residential solar with net metering would generally be politically acceptable.

[xxvii] Source is REN21, pp. 79, 80.[7]

[xxviii] The installation of significant solar rooftop capacity will likely also require the utility to make incremental investments, as discussed in Chapter 7.

[xxix] For a positive discussion of net metering, see Duke, et al.[47] For a recent quantitative analysis of its impact, see Satchwell, Mills, and Barbose.[48]

In broad terms, the economically obvious solution is to move away from the prevalent design of distribution network charges that recovers fixed distribution costs via volumetric (per-kWh) charges.[xxx]

Over the years, governments at all levels have employed policies that attempt to expand the use of renewable energy sources by means other than incentives or regulations.

As discussed in Chapter 7, the ideal approach would be to recover utilities' distribution costs through a system of charges that reflect each individual customer's contribution to those costs, not their kWh consumption. It is not yet clear how this ideal can best be approximated in practice, however.

FINDING:

By enabling those utility customers who install distributed solar generation to reduce their contribution to covering distribution costs, net metering provides an extra incentive to install distributed solar generation. Costs avoided by households that install distributed solar generation are shifted to utility shareholders and/or other customers. Recovering distribution costs through a system of network charges that is more reflective of cost causation and that avoids the current direct dependence on electricity consumption would remove the extra subsidy and prevent this cost shifting.

Over the years, governments at all levels have employed policies that attempt to expand the use of renewable energy sources by means other than incentives or regulations. These policies, which have been termed "enabling" or "catalyzing," often involve education and information campaigns aimed more generally at building awareness and stimulating demand, as well as training programs designed to enhance supply.[xxxi] Efforts by municipalities in various regions to reduce balance-of-system costs for residential PV by, for example, simplifying and coordinating permitting, installation, and inspection; providing residential consumers with better price information; or adopting widely used standards would also fall in this category.[xxxii] Policies that require grid operators to connect to renewable generators are also present in one form or another in 43 states and the District of Columbia and have likewise been characterized as catalyzing renewables deployment, though it may be more appropriate to consider them as simply offsetting distribution utilities' incentives to resist distributed generators for the reasons discussed above.

Since July 2009, grid operators in the EU have been required to "... give priority to generating installations using renewable energy sources insofar as the secure operation of the national electricity system permits..."[54] This policy aims to provide a less uncertain revenue stream to renewable installations and, perhaps more important, to force system operators and owners of conventional generators to develop operating rules that are compatible with large amounts of renewable generation. Since electricity generated from solar energy has zero

[xxx] For a general discussion, see Kassakian and Schmalensee.[50] An alternative approach that has been discussed in some jurisdictions is to deploy two meters to value solar generation at the utility's avoided cost (which should correspond to the wholesale price) and to charge the consumer at the retail rate for all electricity consumed.[49]

[xxxi] For examples and a general discussion, see Lund.[51] See also Taylor.[52]

[xxxii] For a discussion of statewide efforts of this sort in Vermont, see North Carolina Solar Center.[53]

marginal cost, this might seem consistent with economic (i.e., variable-cost-minimizing) dispatch of generating units. But in fact the EU policy constitutes an invisible, but potentially substantial, subsidy to solar (and other renewable) generation sources, and it increases system operating costs.

As discussed in Chapter 8, in areas with a large penetration of renewable generation, it is possible that at times of low electricity demand, some conventional thermal plants may be forced to shut down to allow renewable sources to be run at capacity. If that happens, energy must be expended (and thus costs incurred) to start the conventional plants up again, and these startup costs could well outweigh the variable cost savings from making greater use of renewable generators.[xxxiii] There are also limits on the rate at which the output from thermal plants can be increased. In contrast, output from some renewable technologies, particularly PV and wind, can be varied without incurring additional costs. A requirement that renewable energy sources always have priority thus implies that costs associated with changing the output levels of conventional generating plants must be ignored in dispatch decisions.

It is unclear at the time of this writing how disruptive the EU's policy has been to European electric power systems or how large a subsidy it has provided to solar and other renewable generation technologies. Even after it resulted in a weeklong shutdown of a nuclear plant in Spain, fossil plant operators have not complained about the policy, probably because the extra costs of units that must stop and restart are generally reflected in wholesale prices. The resulting higher prices are passed on to ultimate consumers and benefit all generators. To the best of our knowledge, no similar requirement exists anywhere outside the EU, although distributed PV generators are effectively given priority since they are not subject to control by grid operators.

9.6 POLICY EFFECTIVENESS IN THE UNITED STATES

As noted above, a wide variety of policies to support solar generation has been employed at the federal, state, and local levels in the United States. The costs of federal support policies, which operate through the federal tax system, are borne by all taxpayers, wherever they live. In contrast, the cost of net metering, RPS programs, and other state and local support policies are borne either by state or local taxpayers or by customers of affected electric distribution companies.

A requirement that renewable energy sources always have priority thus implies that costs associated with changing the output levels of conventional generating plants must be ignored in dispatch decisions.

Our discussion of these policies in the foregoing sections has been largely theoretical, and it would be extremely useful to supplement it with analysis of the actual effectiveness of these policies along several dimensions. At the very least, it would be useful to be able to compare generation per dollar of spending on various programs to support solar and other renewable energy technologies. It would be even better to compare the cost per ton of CO_2 emissions

[xxxiii] Thermal generating units fueled by biomass may have marginal costs significantly above those of other thermal units. Giving priority to biomass units would then clearly increase system costs.

avoided via subsidies of various sorts to solar technologies with the per-ton costs of emissions reductions via subsidies to other renewable technologies, as well as the per-ton costs of other programs aimed at reducing greenhouse gas emissions.[xxxiv]

Even if good estimates of emissions avoided were available, however, neither comparison would be possible. In the first place, there is no authoritative compilation of total spending to support the deployment of solar technologies — at the national level or for any particular state — let alone a breakdown of total spending across subsidy programs.[xxxv] Even if these data were available, it would be essentially impossible to apportion credit for increasing renewable generation or reducing CO_2 emissions among the multiple support policies that are currently in place in the United States.

It would be essentially impossible to apportion credit for increasing renewable generation or reducing CO_2 emissions among the multiple support policies that are currently in place in the United States.

And, of course, states' deployment of solar or other renewable technologies depends on more than the support policies in force. California is the clear leader in U.S. PV deployment with 35% of the nation's capacity in 2012.[xxxvi] Is that mainly because of California's aggressive RPS regime and many other renewable support policies or does it mainly reflect the fact that California is a large state with lots of sunshine in many places and very high marginal electricity rates? Arizona comes second with 20% of national capacity. It has an RPS policy that is much less aggressive than California's, but it has a number of other support policies in place, and it also has a lot of sunshine. Finally, New Jersey is third with 7.4% of the nation's PV capacity. New Jersey is a small state without abundant sunshine that offers neither production nor investment tax credits, but it has had an RPS with a very strong solar requirement.

FINDING:

It is not known how much has been spent in the United States or in any individual state to support the deployment of solar generation. There is no empirical support for assessments of the cost effectiveness of individual support policies or of overall U.S. support for expanding solar generation or reducing CO_2 emissions.

In common with the policies of many other countries, **deployment support policies in the United States generally favor distributed, residential-scale PV generation over utility-scale PV generation.** As we noted above, net metering policies have this effect. Because the per-watt investment costs for residential PV are much higher than for utility-scale PV, the federal investment tax credit and accelerated depreciation contribute more per watt at the residential scale than at the utility scale. Both policies have the effect of lowering investment costs by a fraction, and because residential investment costs are larger per watt, so is the per-watt dollar subsidy implied by that fraction. Finally, some state RPS programs have a requirement for distributed generation and distributed generation is mainly solar PV.

[xxxiv] For a recent attempt to measure the cost effectiveness of subsidies to wind power in Texas, see Cullen.[55]

[xxxv] It would thus be impossible to compare solar subsidies in the United States with those in China, even if we knew the level of subsidies in China, which, of course, we do not.

[xxxvi] The state-specific numbers in this paragraph are from EIA.[56]

If the objective of deployment support policies is to increase solar generation at least cost, favoring residential PV makes no sense. The results in Chapter 5 indicate that the per-kWh subsidy necessary to make residential PV competitive in central Massachusetts is 2.2 times the subsidy necessary to make utility-scale PV competitive.[xxxvii] In California, this ratio is 2.9. With a $40/tonne tax on CO_2 emissions, these ratios become 2.4 and 4.1, respectively. That is, any given total subsidy outlay borne by taxpayers and/or electricity consumers — if it is devoted to subsidizing residential-scale PV — will produce only a fraction of the solar electricity that would be produced if the same amount of subsidy were devoted to supporting utility-scale PV generation.[xxxviii] Moreover, as Chapter 7 demonstrates, adding material amounts of distributed PV generation to existing distribution systems will require incremental investments to handle reverse power flows.

FINDING:

Subsidizing residential-scale solar generation more heavily than utility-scale solar generation, as the United States now does, will yield less solar generation (and thus less emissions reductions) per dollar of subsidy than if all forms of solar generation were equally subsidized.

If the objective of deployment support policies is to increase solar generation at least cost, favoring residential PV makes no sense.

9.7 CONCLUSIONS AND RECOMMENDATIONS

At least until the United States introduces a nationwide cap or tax on CO_2 emissions from fossil fuels, there is a case for promoting the use of solar and other renewable technologies that serve to displace fossil fuels. Such deployment is likely to provide additional benefits by reducing local air pollution, contributing to the advancement of solar technologies, and reducing institutional barriers to large-scale future solar deployment. The nature of the climate problem argues for minimizing the total cost of using solar and other generation technologies with negligible CO_2 emissions by any nation, which in turn argues against trying to restrict the flow of technological knowledge or the location of any of the operations in the solar value chain. Policies that aim to restrict the flow of knowledge are unlikely to succeed in any case.

At least until the United States introduces a nationwide cap or tax on CO_2 emissions from fossil fuels, there is a case for promoting the use of solar and other renewable technologies that serve to displace fossil fuels.

[xxxvii] Table 5.1 shows base-case costs for central Massachusetts of 27.6 ¢/kWh for residential PV and 16.1 ¢/kWh for utility-scale PV. Comparing these figures with the 6.69 ¢/kWh cost for a natural gas combined cycle plant yields subsidy requirements of 20.91 ¢/kWh and 9.41 ¢/kWh, respectively. The ratio of the first of these to the second is 2.2. The other numbers in this paragraph are derived similarly, using the southern California base-case costs and then using 8.19 ¢/kWh as the natural gas combined cycle cost with a $40/tonne carbon tax.

[xxxviii] It is worth noting that, despite the high cost of subsidies necessary for residential PV to be competitive, the actual subsidies in force are sufficient to fuel continued rapid growth. Between the first half of 2012 and the first half of 2014, the installed capacity of residential PV in the United States more than doubled. However, even though the existing subsidy regime favors residential PV, the capacity of utility-sale PV quadrupled over the same period.[57]

RECOMMENDATION:

Policies that attempt to restrict trade, investment, or knowledge transfers in solar technologies are generally undesirable since they make it harder to reduce global carbon dioxide emissions and advance solar technologies, and they are unlikely to yield sustainable national competitive advantage.

There is no obvious short-run environmental case for singling out solar energy for more aggressive deployment support than other renewable technologies; moreover, since solar tends to be more expensive than other renewable technologies (particularly onshore wind), there is a clear short-run economic cost. On the other hand, as we have noted at several points, the potential of solar power to be scaled up dramatically to meet global energy needs in a low-carbon future means that the long-run benefits of advancing solar technology and addressing the problems associated with dramatically increasing its use may exceed those of advancing other renewable technologies. And it seems plausible that ensuring a market for PV and concentrated solar power contributes to the advancement of those technologies. However, subsidizing the deployment of currently available solar technologies is not likely, by itself, to improve U.S. competitiveness or achieve other goals that have been discussed in this context, particularly in the absence of barriers to the free flow of goods, ideas, and investment capital.

The potential of solar power to be scaled up dramatically to meet global energy needs in a low-carbon future means that the long-run benefits of advancing solar technology and addressing the problems associated with dramatically increasing its use may exceed those of advancing other renewable technologies.

RECOMMENDATION:

Policies to support the deployment of solar technologies should be justified by their impact on global CO_2 emissions, on local air pollution, and, if appropriate, on the advancement of solar technology and the reduction of institutional and other barriers to substantially increasing its penetration.

This chapter's main message is that the current regime of U.S. policies for promoting solar-powered electricity generation is needlessly inefficient and delivers much less generation bang for the subsidy buck than obvious alternatives could produce. That regime, with its vast array of federal, state, and local subsidy and regulatory programs, many of which have hidden costs, stands in stark contrast to the simple and transparent support regimes used in many other nations. The United States can get much more solar generation per dollar of taxpayer and ratepayer expenditure by moving toward well-designed, national policies. In order to increase reliance on solar energy substantially at politically acceptable costs, it will likely be necessary both to reduce the cost of solar electricity through research, development, and demonstration (RD&D), as discussed in the next chapter, and, as discussed in this chapter, to increase the \$/kWh efficiency of solar deployment support policies. Output subsidies, feed-in tariffs, and renewable portfolio standards are all superior in principle to subsidizing investment via the tax system. Such subsidies are the federal government's main incentive device and are also widely used at the state and local levels. Using tax credits rather than direct expenditures reduces both transparency and generation per dollar of public expenditure. If tax credits must be used, the need for solar project developers to access the tax equity market should be reduced or eliminated, perhaps by making tax credits freely tradable.

RECOMMENDATION:

Subsidies for solar and other renewable technologies should reward generation, not investment, and should reward generation more when it is more valuable.[xxxix] Tax credits should be replaced by direct grants, which are more transparent and more effective. If this is not possible, steps should be taken to avoid dependence on the tax equity market.

State RPS regimes generally do not reward generation more when it is more valuable. Even putting this serious problem aside, the current system of multiple, incompatible state RPSs with limited interstate trading needlessly inflates nationwide costs for any level of renewable generation attained. If an output quota approach like RPS is employed, it should be employed uniformly across the nation and phased out when a comprehensive carbon policy is in place and the subsidized technology is mature. If a nationwide RPS is not feasible, state programs should permit unlimited interstate trading to avoid forcing renewable generators to be built at undesirable locations.

RECOMMENDATION:

RPS programs should be replaced by subsidy regimes that reward generation more when it is more valuable. If that is not feasible, state RPS programs should be replaced by a uniform nationwide program. If a nationwide RPS is not feasible, state RPS programs should permit interstate trading to reduce costs per kWh generated and should adopt common standards for renewable generation to increase competition.

Finally, as we have discussed at several points, because residential PV generation is much more expensive than utility-scale PV generation, the subsidy cost per kWh of residential PV generation is substantially higher than the per-kWh subsidy cost of utility-scale PV generation. There is no compensating difference in benefits and thus there is simply no good reason to continue to provide more generous subsidies for residential-scale PV generation than for utility-scale PV generation.

RECOMMENDATION:

Residential PV generation should not continue to be more heavily subsidized than utility-scale PV generation. Eliminating this uneconomic disparity will require replacing per-kWh distribution charges with a system for recovering utilities' distribution costs that reflects network users' impacts on those costs.

[xxxix] This assumes that the market power issue mentioned in Footnote x can be directly addressed by restrictions on the ownership of generation facilities.[58]

Net metering with per-kWh charges to cover distribution cost is an important reason why residential PV generation is more heavily subsidized than utility-scale PV generation. In addition, net metering raises equity issues: it is far from obvious that it is fair for consumers with rooftop PV generators to shift the burden of covering fixed distribution costs to renters and others without such systems. Chapter 7 discusses the use of reference network models to allocate distribution costs among utility customers according to how their network usage profile contributes to those costs.[58] The discussion in Chapter 7 also notes the existence of a host of implementation issues, however, including the political acceptability of potentially very different charges for apparently similar network users. Because of the problems associated with net metering, research directed at developing a more efficient, practical, and politically acceptable system for covering fixed network costs should be a high priority.

While the current system of policies to support solar deployment in the United States is needlessly wasteful, it does not follow (and we do not believe) that such support should be ended. As noted at several points, we favor continued support of solar deployment in order to encourage industrial research and develpment and work on institutional and other barriers to greater reliance on solar energy and to produce environmental benefits. As the recommendations above make clear, however, we believe that the system of solar support policies should be reformed to increase its efficiency, so that more solar generation is produced per taxpayer and electricity-consumer dollar spent.

RECOMMENDATION:

Research should be undertaken to develop workable methods for using reference network models to design pricing systems that cover fixed network costs via charges that depart from simplistic proportionality to electricity consumption and that respect the principle of cost causality.

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The hyperlinks in this document were active as of April 2015.

APS 2014 Integrated Resource Plan – Table 1.

EXHIBIT
APS-16
ADMITTED

TABLE 1 - SUMMARY LOADS AND RESOURCES

2014 IRP (VALUES IN MW AT PEAK)				
	2014	**2019**	**2024**	**2029**
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
EXISTING RESOURCES AS OF DEC. 31, 2013				
APS-Owned Generation	6,315	6,086	6,063	6,066
Long-Term Contracts	2,872	1,490	389	346
Total Existing Resources as of Dec. 31, 2013	**9,187**	**7,576**	**6,452**	**6,412**
FUTURE* PROJECTED CUSTOMER RESOURCES				
Energy Efficiency	109	877	1,230	1,447
Distributed Energy	45	109	203	261
Demand Response	0	0	150	275
Total Future* Customer Resources	**153**	**986**	**1,584**	**1,983**
FUTURE* PROJECTED GENERATION RESOURCES				
Natural Gas	0	1,010	3,030	4,205
Renewable Energy	0	57	295	425
Total Future* Projected Utility Resources	**0**	**1,067**	**3,325**	**4,630**
Total Future* Projected Resource Additions	**153**	**2,053**	**4,909**	**6,613**
Total Resources	**9,340**	**9,630**	**11,361**	**13,025**

*Future resources added after December 31, 2013

aps