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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
TOM FORESE COMMISSIONER	ANDY TOBIN COMMISSIONER	

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023** **THE ALLIANCE FOR SOLAR CHOICE'S (TASC) NOTICE OF FILING DIRECT TESTIMONY OF B. THOMAS BEACH**

The Alliance for Solar Choice ("TASC") hereby provides notice of filing the Direct Testimony of B. Thomas Beach in the above referenced matter.

RESPECTFULLY SUBMITTED this 25th day of February, 2016.

Court S. Rich
Attorney for The Alliance for Solar Choice

Arizona Corporation Commission
DOCKETED
FEB 25 2016

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By: ______________________

Executive Summary

This testimony responds to the Commission's request that parties file proposals on how to value distributed generation resources in Arizona. My testimony proposes a benefit-cost methodology for valuing DG resources that builds upon the widely-used, industry-standard approach to assessing the cost-effectiveness of other types of demand-side resources. I illustrate this methodology with a new analysis of the benefits and costs of solar DG for Arizona Public Service ("APS"), which is **Exhibit 2** to this testimony.

There is a developing consensus in the utility industry on the best practices for designing benefit-cost analyses of net metering and distributed resources, a consensus which draws upon the similar analyses which have become standard practice for other types of demand-side resources. These analyses assess the benefits and costs of these resources from multiple perspectives, including those of the principal stakeholders in DG development, including (1) participating customer-generators, (2) other non-participating ratepayers, and (3) the utility system and society as a whole. The goal of the regulator should be to balance the interests of all of these stakeholders, who collectively constitute the public interest in developing DG technologies.

This testimony also presents a close analysis of the net metering transaction, for several reasons. First, it illuminates how DG differs from other demand-side resources. DG customers are not just consumers of power, but also at times produce power for export to the utility system. Second, I discuss why the essence of net metering is valuing the power which DG customers will export to the grid. Third, I dispel several common myths about net metering, including the misplaced ideas that NEM customers use the grid more than regular utility customers, that a NEM customer with a low or zero bill means that the customer has not paid for its use of the grid, and that the grid serves to "store" DG output for future consumption. In sum, I suggest that the appropriate framework for assessing the relative benefits and costs of net metering is to focus on the value that customer receives for the electricity that is exported from their premises.

The Commission should adopt a benefit/cost methodology for NEM and DG that has four key attributes:

1. Examine and balance the benefits and costs from the multiple perspectives of the key stakeholders.
2. Consider a comprehensive list of benefits and costs.
3. Use a long-term, life-cycle analysis.
4. Focus on NEM exports.

I discuss recent benefit-cost studies of net-metered solar resources in Nevada, California, and Mississippi, which also have examined the benefits and costs from these multiple perspectives. I also discuss the unfortunate recent results in Nevada, when the Nevada commission moved to rely solely on a short-term, cost-of-service framework that does not share any of these attributes. I recommend that the methodology adopted in Arizona should take care to include all four of these key features, with the details of Arizona's approach tailored to its specific loads, resources, and costs.

The testimony briefly reviews the specific benefits and costs that should be examined and quantified in establishing the value of DG. All of these benefits and costs have been quantified in other similar studies, and well-accepted techniques are available for this task. If there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that benefit or cost, but to examine several cases that span a range of reasonable values for this benefit or cost.

Accompanying this testimony is a new study of the benefits and costs of solar DG for Arizona Public Service, which applies TASC's recommended methodology to the example of a specific utility in Arizona. This study concludes:

- **Solar DG is a cost-effective resource** for APS, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

- There is a **balance between the costs and benefits of residential DG** for both participants and non-participants, as shown by the results for the Participant and Ratepayer Impact Measure tests.

- The **benefits of DG significantly exceed the costs in the commercial market**. Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the APS system.

- The **benefits of solar DG in APS's service territory are higher for west-facing systems**. If there is a concern about the cost of DG to non-participating ratepayers, west-facing systems should be encouraged and incentivized, particularly for residential customers.

- The analysis indicates **lower costs of solar DG to non-participants under APS's existing residential time-of-use (TOU) rates**. Thus, encouraging greater use of TOU rates also will improve the cost-effectiveness of solar DG.

The cost-effectiveness test results for APS's residential and commercial markets are shown in the following figures.

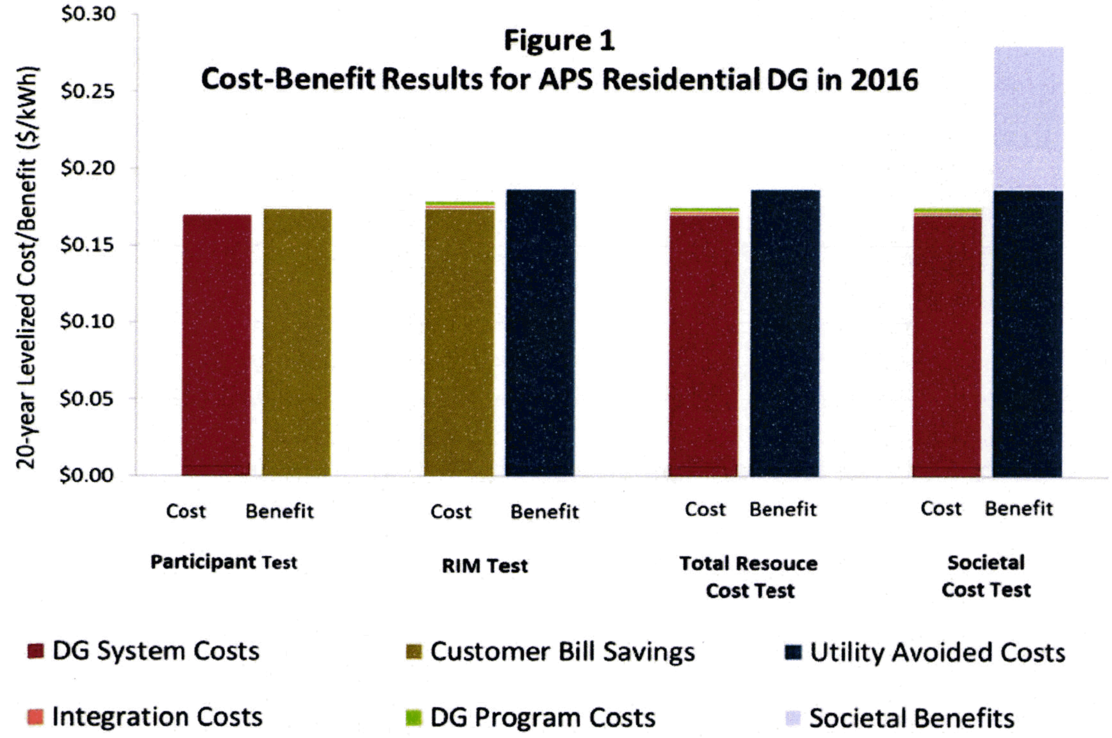

Figure 1
Cost-Benefit Results for APS Residential DG in 2016
20-year Levelized Cost/Benefit ($/kWh)
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Cost
Benefit
Participant Test
RIM Test
Total Resouce Cost Test
Societal Cost Test
DG System Costs
Customer Bill Savings
Utility Avoided Costs
Integration Costs
DG Program Costs
Societal Benefits

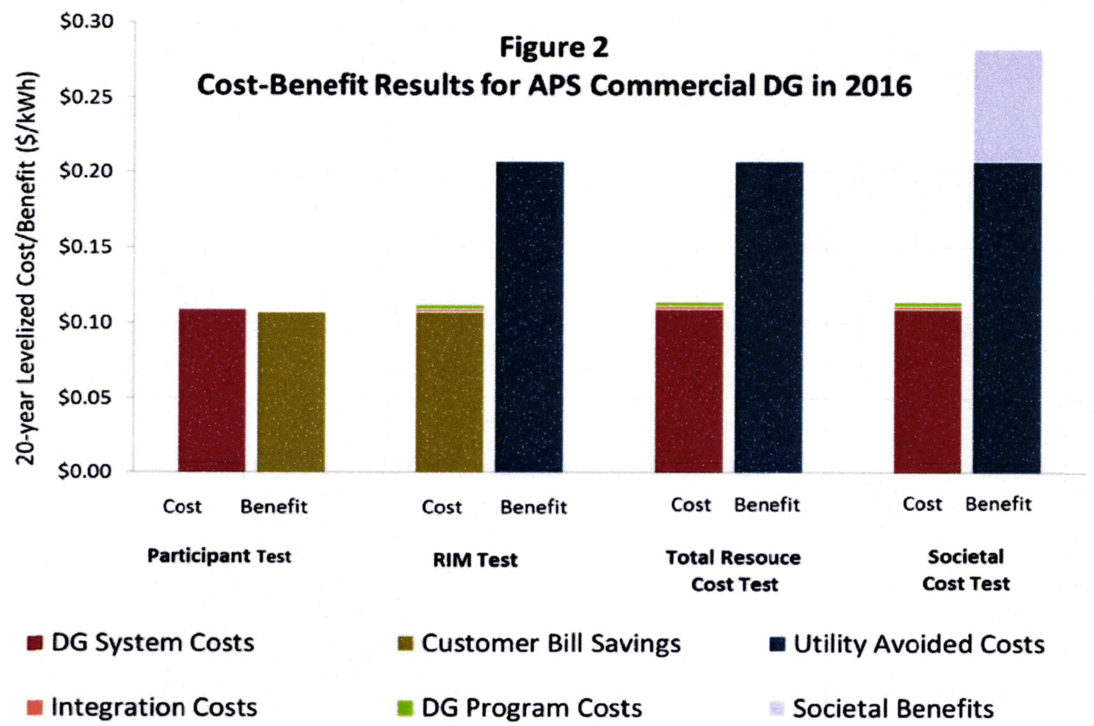

Figure 2
Cost-Benefit Results for APS Commercial DG in 2016
20-year Levelized Cost/Benefit ($/kWh)
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Cost
Benefit
Participant Test
RIM Test
Total Resouce Cost Test
Societal Cost Test
DG System Costs
Customer Bill Savings
Utility Avoided Costs
Integration Costs
DG Program Costs
Societal Benefits

The testimony next discusses how the results of the adopted methodology can be used to make cost of service or rate design changes, if necessary, that impact the balance of the interests of the affected stakeholders. The types of changes that the Commission should prioritize are those that align rates more closely with utility costs, such as time-of-use rates, or that continue to allow the greatest scope for customers to exercise the choice to adopt DG, such as a minimum bill. Fixed charges or rate design changes that apply only to DG customers should be avoided, due to problems with customer acceptance, undue discrimination, and the future potential for customer bypass of the utility system.

The last section of the testimony discusses comparisons between the costs of utility-scale and rooftop solar systems. Utility-scale solar has lower capital costs, as a result of economies of scale. However, this is not an apples-to-apples comparison, because the two types of solar do not provide the same energy product. Rooftop solar provides a retail product, while utility-scale solar supplies a wholesale product. The retail, rooftop product has been delivered to load, whereas the wholesale, utility-scale product has not. 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.

Finally, there are important policy reasons to treat rooftop solar equitably, so that consumers continue to have the freedom to exercise a competitive choice and to become more engaged and self-reliant in providing for their energy needs.

Table of Contents

I. Introduction / Qualifications

Q1: Please state for the record your name, position, and business address.

A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q2: Please describe your experience and qualifications.

A2: My experience and qualifications are described in my *curriculum vitae*, attached as **Exhibit 1**. As reflected in my CV, I have more than 30 years of experience in the natural gas and electricity industries. I began my career in 1981 on the staff at the California Public Utilities Commission ("CPUC"), working on the implementation of the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). Since 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony on numerous occasions before state regulatory commissions in Arizona, California, Colorado, Idaho, Minnesota, Nevada, New Mexico, North Carolina, Oklahoma, Oregon, Georgia, South Carolina, Texas, Utah, Vermont and Virginia. My CV includes a list of the formal testimony that I have sponsored in various state regulatory proceedings concerning electric and gas utilities.

Q3: Please describe more specifically your experience on benefit-cost issues concerning distributed generation.

A3: In addition to working on the initial implementation of PURPA while on the staff at the CPUC, in private practice I have represented the full range of qualifying facility ("QF") technologies – both renewable small power producers as well as gas-fired cogeneration QFs – on avoided cost pricing issues before the utilities commissions in California, Idaho, North Carolina, Oregon, Utah, and Nevada. With respect to benefit-cost issues concerning renewable distributed generation ("DG"), I have sponsored testimony on net energy metering ("NEM") and solar economics in California, Colorado, Idaho, Minnesota, New Mexico, North

Carolina, South Carolina, Texas, and Virginia. In the last three years, I have co-authored benefit-cost studies of NEM or distributed solar generation in Arizona (focusing on Arizona Public Service ["APS"]), Colorado, North Carolina, and California. I also co-authored a chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools to address key questions concerning distributed generation resources.

Q4: On whose behalf are you testifying in this proceeding?

A4: I am testifying on behalf of The Alliance for Solar Choice ("TASC").

II. Background

Q5: Why is the Commission considering proposals for a cost-benefit methodology through this proceeding?

A5: The Commission initiated this generic investigation to review NEM issues and to help inform future Commission policy on the value that DG installations bring to the grid. On October 20, 2015, the Commission ordered that an evidentiary hearing be held in this generic docket, at which the parties should present testimony with "their proposals regarding cost of service to DG customers and value of DG, including any studies and methodologies."

Q6: Is your testimony limited to the "value of DG" aspect of this proceeding?

A6: My testimony focuses on how the Commission should establish the long-term value of DG, through an analysis of the benefits and costs of DG technologies. In that regard I sponsor both this testimony on the methodology to determine the value of DG as well as a study that applies this recommended approach to a specific Arizona utility, APS. I also comment on how and why the results of this methodology should inform any further investigation of the cost of service and the rates that are applied to DG customers, or of future changes to the structure of NEM in Arizona.

III. Proposal for a Benefit-Cost Methodology for Net-Metered DG

A. National Context: Toward a Consistent Approach

Q7: Is there a developing consensus on the best practices for designing benefit-cost analyses of behind-the-meter DG resources, including solar photovoltaic (PV) systems, that should inform how the Commission undertakes this analysis?

A7: Yes, there is. In this regard, the first and perhaps most important observation is that the issues raised by the growth of demand-side DG are not new. The same issues of impacts on the utilities, on non-participating ratepayers, and on society as a whole arose when state regulators and utilities began to manage demand growth through energy efficiency ("EE") and demand response ("DR") programs. To provide a framework to analyze these issues in a comprehensive fashion, the utility industry developed a set of standard cost-effectiveness tests for demand-side programs.[1] These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole.

This framework for evaluating demand-side resources is widely accepted, and state regulators have years of experience overseeing this type of cost-effectiveness analysis, with each state customizing how each test is applied and the weight which policymakers place on the various test results. This suite of cost-effectiveness tests is now being adapted to analyses of NEM and demand-side DG more broadly, as state commissions recognize that evaluating the costs and

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[1] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF .

benefits of all demand-side resources – EE, DR, and DG – using the same cost-effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.

Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 1** below. "+" denotes a benefit; "-" a cost.

Table 1: *Demand-side Cost/Benefit Tests*

Perspective (Test)	DG Customer (Participant)	Other Ratepayers (RIM)	Total Resource Cost to Utility or Society (TRC or Societal)
Capital and O&M Costs of the DG Resource	–		–
Customer Bill Savings or Utility Lost Revenues	+	–	
Benefits (Avoided Costs) -- Energy -- Hedging/market mitigation -- Generating Capacity -- T&D, including losses -- Reliability/Resiliency/Risk -- Environmental / RPS		+	+
Federal Tax Benefits	+		+
Program Administration, Interconnection & Integration Costs		–	–

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. A program will need to pass the Participant test if it is to attract customers by offering them an economic benefit for their participation – thus, their bill savings and tax benefits should be comparable to the cost of participating. The program also should be a net benefit as a resource to the utility system or society more broadly – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of the program to its benefits. In the TRC Test, those benefits are principally the costs which the utility can avoid from the reduction in demand for electricity. The Societal Test adds the broader benefits to citizens as whole, benefits that may not be reflected in utility rates. The Ratepayer Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers: if the utility's lost revenues and program costs are greater than its avoided cost benefits, then rates may rise for non-participating ratepayers in order to recover those costs. This can present an issue of equity among ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all parties are likely to benefit from the program. However, it is a test that measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC and Societal tests).

B. Experience in Other States: Nevada, California, and Mississippi

Q8: Can you provide examples of other state commissions which have developed analyses of NEM from the three perspectives which you have described?

A8: Yes. The Public Utilities Commission of Nevada ("PUCN") adopted this multi-perspective approach in the net metering study which it released on July 1, 2014.[2] The consulting firm Energy and Environmental Economics (E3) performed the analytic work for this study, and I served on a Stakeholder Committee that the PUCN convened to provide input on the study methodology and analysis. **Figure 3** below shows the costs and benefits of net-metering for solar PV systems in Nevada going forward, in the years 2014-2016, from each of the key stakeholders' perspectives.[3]

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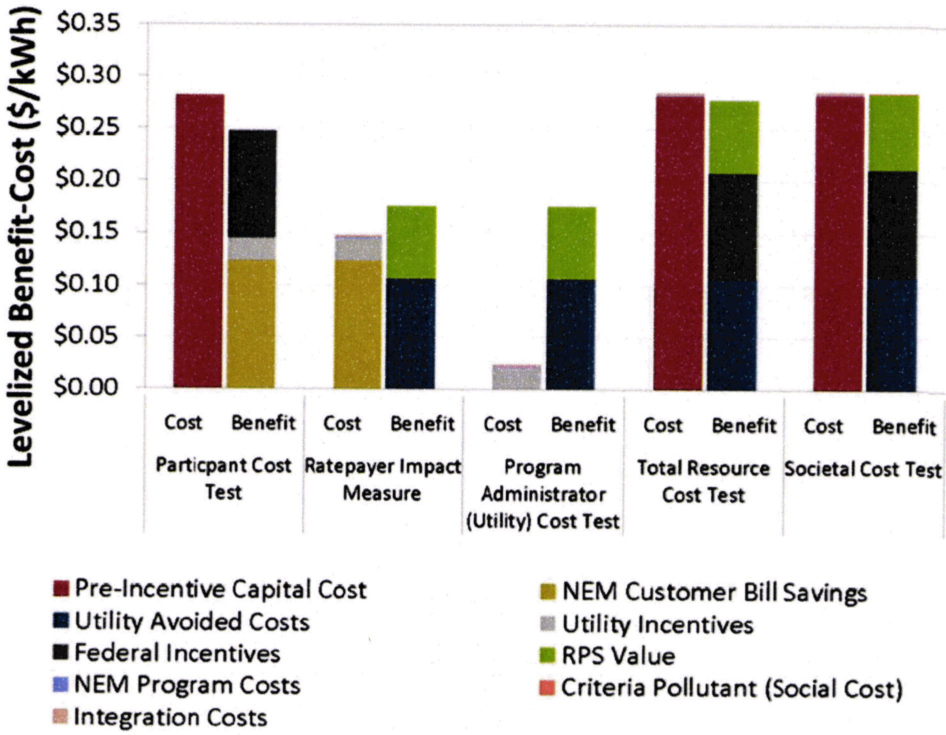
2 The PUCN's net metering study, including the spreadsheet models used in the study, can be found at: http://puc.nv.gov/About/Media_Outreach/Announcements/Announcements/7/2014_-_Net_Metering_Study/ .

3 This figure is from the "Results" tab of the "Nevada Public Tool" model, with the model set to produce results for solar PV and for the going-forward period of 2014-2016.

Figure 3: *Public Utilities Commission of Nevada NEM Benefit-Cost Results*



Notably, the Nevada study showed that NEM is cost-effective for non-participating ratepayers (*i.e.*, the benefits in the RIM test exceeded the costs), while the costs are somewhat higher than the benefits for participants (*i.e.*, for solar customers). As with any such set of cost-effectiveness tests, it is not reasonable or practical to expect each of these tests to achieve a precise 1.0 benefit/cost ratio. Instead, the goal should be to achieve a reasonable, equitable balance of benefits and costs for all concerned – solar customers, other ratepayers, and the utility system as a whole. In my judgment, the Nevada study demonstrated that NEM at the full retail rate, without any further rate design modifications, achieved that desired "rough justice" balance of interests in Nevada.

Q9: Did the Nevada Commission subsequently move away from the use of a long-term benefit-cost approach to analyze NEM in that state?

A9: Yes, it did. In 2015, in response to new legislation, the PUCN reviewed a study from NV Energy that was limited to the short-term cost of service for residential and small commercial customers who install solar DG. The PUCN's recent decision on December 23, 2015 accepted the results of that study, and, based on that evidence, found that there was a significant cost shift from non-participating ratepayers to solar DG customers. As a result, the PUCN ended NEM in Nevada, increased the fixed monthly customer charge for DG customers, and reduced the export rate credited to DG systems from the full retail rate (about 11 cents per kWh for residential customers) to an energy-only avoided cost rate of 2.6 cents per kWh. The PUCN took this action even though its order found that there are the following 11 components to the value of DG (based on an adopted stipulation on NEM issues from South Carolina), and that it was only able to quantify the first two components of DG value in the adopted 2.6 cents per kWh export rate:

1. Avoided energy costs
2. Line losses
3. Avoided capacity
4. Ancillary services
5. Transmission and distribution capacity
6. Avoided criteria pollutants
7. Avoided CO_2 emission costs
8. Fuel hedging
9. Utility integration and interconnection costs
10. Utility administration costs
11. Environmental costs[4]

Q10: What has been the result of the PUCN decision?

A10: The reduction in the export rate and the increased fixed charge have reduced the bill savings available to NEM customers in Nevada by 40% or more. DG is no longer economic for new systems, and existing customers who expected modest savings from their solar investments now face substantial added costs for electric service. Even though the PUCN has subsequently decided to phase-in the new DG rates over a 12-year period, the elimination of NEM and, in particular, the reduction in the export rate, has decimated the rooftop solar market in Nevada, resulting in more than 1,000 documented layoffs at solar companies.[5] The

[4] See PUCN December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042, at pp. 66-67 and 95-96.

[5] See *Prepared Direct and Rebuttal Testimonies of R. Thomas Beach on behalf of TASC*, served February 1 and 5, 2016 in PUCN Dockets Nos. 15-07-041 and 15-07-042.

controversy has been particularly heated because the PUCN applied the new rates to existing solar customers as well as to prospective ones. The changes have sparked significant public outcry, a ballot initiative, and lawsuits from unhappy customers whose investments in renewable DG have been severely and unexpectedly been made uneconomic.[6]

Q11: Did the California Public Utilities Commission recently review the benefits and costs of net metered DG?

A11: Yes. The investor-owned utilities in California are approaching that state's 5% cap on NEM systems. In 2015, the California Commission asked parties to analyze their proposals for a NEM successor tariff using a common "Public Tool" spreadsheet program similar to the Nevada NEM benefit-cost model. Like the Nevada model, the California Public Tool analyses a proposed tariff from multiple perspectives, using all of the SPM's cost-effectiveness tests and looking at the long-term, life-cycle costs and benefits. The CPUC received detailed analyses of NEM benefits and costs using the Public Tool from a variety of parties. In January 2016, the California commission decided to extend NEM in California until a further review in 2019, with certain changes such as requiring NEM customers to be on time-of-use ("TOU") rates, removing certain public benefit charges from export rates, and requiring NEM customers to pay interconnection costs. The CPUC's order does not rely on the Public Tool analyses, because important information related to both costs (rate design changes) and benefits (locational benefits on the distribution grid and societal benefits) remain under development in other CPUC proceedings. However, the CPUC made clear that it intends to continue to refine and to use this SPM-based, long-term benefit-cost approach in its future evaluations of NEM and DG.[7]

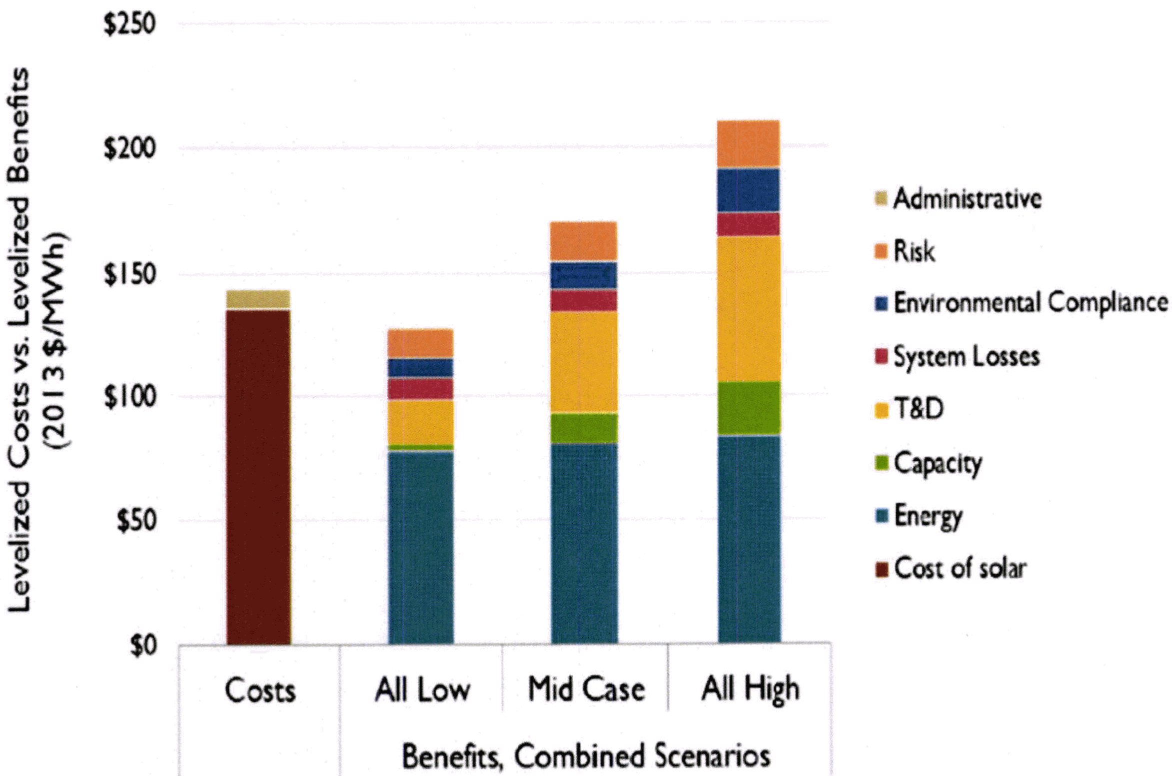
Q12: Do you have any other recent examples?

[6] For example, see "Regulators vote against grandfather clause for existing solar customers" (*Las Vegas Sun*, February 12, 2016), available at http://m.lasvegassun.com/news/2016/feb/12/regulators-vote-against-grandfather-clause-for-exi/#.VsN4d5tCIss.twitter.

[7] See CPUC Decision 16-01-044, at pp. 48-50, 54-61, and 80-82.

A12: Yes. The Public Service Commission of Mississippi completed a NEM benefit/cost analysis in 2014, and NEM is being implemented for the first time in Mississippi.[8] As in the Nevada NEM study, the Mississippi study considered the three principal perspectives discussed above, with a focus on the TRC test because that test best captures the benefits and cost for the state as a whole from this new resource. The Mississippi study also used a 25-year time horizon. The following figure summarizes the mid-case costs and benefits from Mississippi's TRC analysis, plus the maximum low and high sensitivity cases for the benefits.

Figure 4: *Public Service Commission of Mississippi NEM Study Results*



As a result of this analysis, the Mississippi study concluded that net metered solar projects will provide a net benefit to Mississippi in almost all of the cases considered. However, the study's analysis of the Participant cost test expressed

[8] Elizabeth A. Stanton, et al., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* (Synapse Energy Economics for the Public Service Commission of Mississippi, released September 19, 2014); hereafter "Mississippi Study." Available at http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf .

concern that NEM bill savings at the retail rate will not provide adequate benefits to drive significant adoption of solar DG in the state. As a result, the study suggested that solar customers should be compensated at a rate <u>higher</u> than retail rates. This higher rate would be based on the utilities' avoided cost benefits, so that it would not shift costs to non-participants.[9] Finally, the Mississippi Study criticized the use of the traditional RIM test, particularly in the context of a new NEM program. The problem with the RIM test is that the cost shift measured by the RIM test is simply a re-allocation of costs which the utilities have already incurred and which are not incremental costs resulting from the NEM program. Due to this limitation, the RIM test should not be used to judge the merits of the new NEM program.[10]

C. The DG Customer as "Prosumer"

Q13: The framework you have proposed and illustrated with examples from the Nevada, California, and Mississippi commissions draws on benefit/cost analyses used for other types of demand-side programs. But isn't there a crucial difference between DG and other demand-side resources: DG is generation that at times can supply power to the grid, whereas EE and DR only reduce the demand for power?

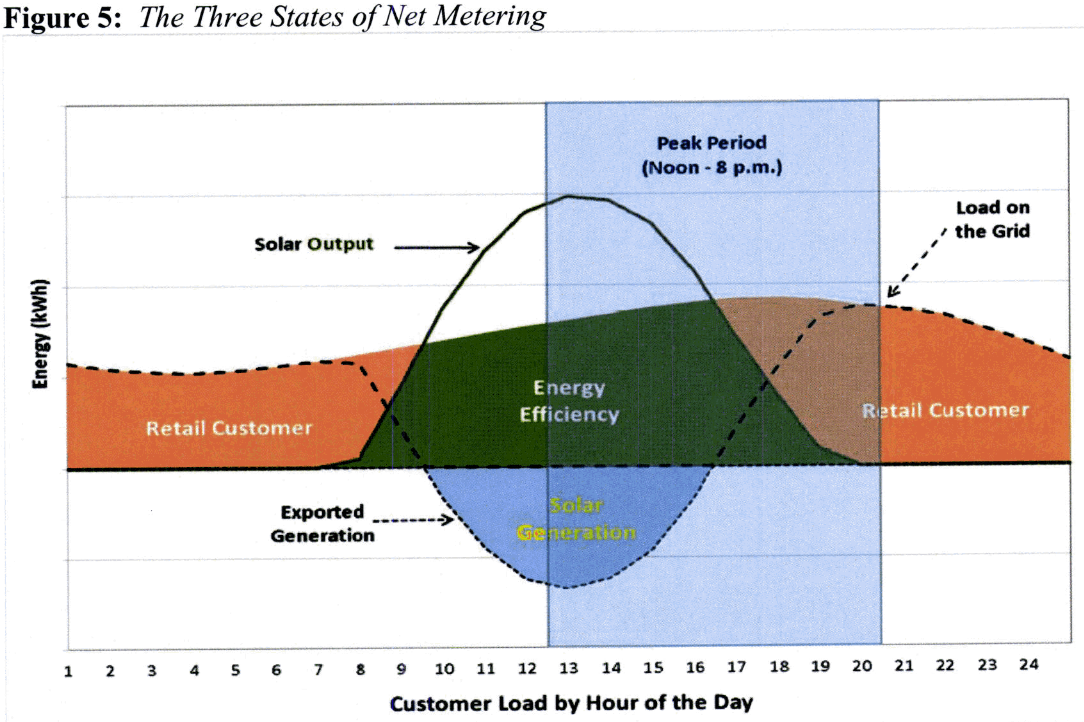
A13: This difference exists, is important, and should be considered. DG located behind the meter will both reduce the demand for power from the utility, and, at times, will supply power to the utility. When a DG system produces more power than the on-site load requires, the excess is exported to the grid, and the DG owner is no longer a consumer, but becomes a supplier (i.e. a generator). Some have applied a new label – "prosumers" – to DG customers in recognition of this dual role. Appreciating these multiple roles is important, and should be considered in establishing the framework for evaluating the benefits and costs of DG.

[9] Mississippi Study, at 49-50.
[10] *Ibid.*, at 41-43 and Figure 18.

Q14: Please explain these multiple roles in more detail, using the example of a typical residential NEM customer.

A14: To illustrate in detail how net metering works, **Figure 5** shows the three different "states" of a residential net-metered PV system over the course of a day:

Figure 5: *The Three States of Net Metering*



- **The "Retail Customer State."** There is no PV production – for example, at night. At this time, the customer is a regular utility customer, receiving its electricity from the grid. The utility meter rolls forward, and the customer pays the full retail rate for this power.

- **The "Energy Efficiency State."** In this state, the sun is up, and there is some PV production but not enough to serve all of the customer's instantaneous load. The customer is supplied with power from the solar PV system as well as with power from the utility. Onsite solar reduces the customer's load on the utility's system in the same fashion as an energy efficiency measure. None of the solar customer's PV production flows out to the utility grid, the meter continues to roll forward, and the customer will pay the utility the full retail rate for his net usage from the grid during these hours.

- **The "Power Export, or Net Metering, State."** In this state, the sun is high overhead, and PV production exceeds the customer's instantaneous use. The on-site solar power serves the customer's entire load, and excess PV generation flows onto the utility's distribution circuit. The utility meter runs backward, producing a net metering credit for the solar customer. In these hours, the solar customer is no longer just a consumer, but is also a producer of power, i.e. a generator. The net metering credit is the solar customer's compensation for the generation it is supplying to the grid. As a matter of physics, the exported power will serve neighboring loads with 100% renewable energy, displacing power that the utility would otherwise generate at a more distant power plant and deliver to that local area over its transmission and distribution system.

This state is the only one in which the customer's generation touches the utility's distribution system or in which a bill credit is produced. In typical PV installations, the percentage of solar output exported to the utility is, on average, about one-third of total PV production; the export percentage can vary above or below this average, depending on the size of the PV system and the hourly profile of the host customer's load. Residential solar customers tend to export a higher percentage of their power output than commercial solar customers.

Q15: What do you conclude from this description?

A15: Net metering only provides bill credits for power exported to the grid. On-site generation from customer-sited PV that is not exported, i.e., electricity generated in the Energy Efficiency State in Figure 3, is not compensated through net metering. In that case, the customer simply uses his on-site generation to reduce his load, and to the utility the installation of such a DG system appears no different than if the customer had installed a more efficient air conditioner or simply decided to reduce his power usage in the middle of the day. In fact, if the solar customer did not export power to the grid and 100% of the solar output was consumed on-site, there would be no need for NEM.

Thus, the essence of NEM is the ability of a customer with a solar PV system to "run the meter backwards" when the customer has more generation than the on-site load and is serving as a generation source for the utility system. When the meter runs backward, the DG customer receives credit for his generation exports in the form of a retail rate credit from the utility. In the accounting used to calculate the DG customer's bill, the customer can use these credits to offset the cost of usage from the grid when the meter runs forward.

Q16: Please discuss the implications for evaluating NEM of the fact that most DG customers are "qualifying facilities" (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA).

A16: As generators, renewable DG customers typically have legal status as QFs under PURPA. As a result, the serving utility is required under this federal law to do the following:

- to interconnect with a customer's renewable DG system,
- to allow a DG customer to use the output of his system to offset his on-site load, and
- to purchase excess power exported from such systems at a state-regulated price that is based on the utility's avoided costs.[11]

These provisions of federal law are independent of whether a state has adopted NEM; thus, the adoption of NEM only impacts the accounting credits which the customer-generator receives for power exports to the grid, and the analysis of the economics of NEM should focus on those exports.

An important implication of the focus on exports is that, even if it is found that there is a "cost shift" from solar DG customers to non-participating ratepayers, any calculation of such a cost shift should only consider the power exported by DG customers, not the DG output that a customer uses on-site, behind the meter, without the power ever touching the grid. As noted above, DG exports are typically a minority, often just 30% to 40%, of DG production. There are always cost shifts when a customer reduces the demand placed on the grid, or shifts load to a different time period, as the result of many types of actions that utilities and regulators encourage – energy efficiency, demand response, or using DG to serve your own load. Such actions by DG customers should not be singled out, penalized, or treated differently than other steps that consumers take to manage their energy demand and reduce their utility bills.

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[11] The PURPA requirements can be found in 18 CFR §292.303.

D. Exploding Common Myths about Net Metering

Q17: Does the fact that DG customers can be both consumers and producers of electricity mean that they make more use of the utility system than regular utility customers?

A17: No. The DG customer either imports power from, or exports power to, the utility's distribution system. When the DG customer imports power from the utility, the customer is using the utility system (including generation, transmission, and distribution), and the meter runs forward. The customer pays the standard tariff rate for that service, including the utility's standard charges for generation and for delivery of the power over the utility's transmission and distribution ("T&D") system.

With exported power, it is not the solar customer who is using the utility system, it is the utility and the solar customer's neighbors, because the title to the exported power transfers to the utility at the solar customer's meter. This is no different than when the utility buys power from any other type of generator – the generator is not responsible for and does not have to pay to deliver the power to the utility's customers. Instead, that delivery service becomes the utility's responsibility when it accepts and takes title to the exported power at the generator's meter. As a generator, the only utility costs for which the generator may be responsible are the incremental costs of interconnecting to the utility system to enable the transfer of generation (and these are often paid by the customer-generator).

As a matter of fact, the utility will save money by using the solar customer's exported power to serve the neighbors, because the utility will avoid the costs of the power that the utility would otherwise have had to generate at a more distant power plant and deliver to that local area over its transmission and distribution system. The essential public policy issue with net metering is whether these "avoided costs" which the utility saves are less than, equal to, or greater than the sum of (1) the net metering credit that the utility provides to the solar customer and (2) the utility's integration and program costs.

Q18: So if a NEM customer ends up with a small, zero, or even negative bill at the end of a month, does this mean that the NEM customer is not paying for the utility service the customer is receiving?

A18: Absolutely not. First, whenever the solar customer uses the utility system (by importing power and rolling the meter forward), the solar customer pays fully for the use of the utility system, at the same rate as any other customer. If the solar customer ends the month with a small or zero bill from the utility, this is the result of crediting the customer for the value of the power which <u>the customer supplies to the utility</u> (from exporting power and running the meter backwards). These credits can offset the solar customer's costs of utility service when the customer imports power and the meter runs forward. However, these credits are not the result of the solar customer's use of the utility system; instead, they are the means to account for the exported generation which the solar customer has provided to the utility at the meter. Thus, the solar customer has paid fully for all actual use which the customer has made of the utility system, even though the customer's net bill at the end of the year may be small or even zero. There is the public policy issue of whether the bill credits for exported power at the retail rate are the right credit for those exports – and this case focuses on the methodology for analyzing this issue – but this does not change the fact that the solar customer has paid fully for his or her actual use of the utility system.

Q19: Doesn't the utility incur costs to "stand by" to serve a solar customer when the solar customer is exporting power to the grid?

A19: No. The costs which the utility incurs to serve a solar customer are no different than those it incurs to stand by to serve a regular utility customer whose usage for periods may be very low – for example, in the middle of the day when the occupants of a house are away at work and school – but who may suddenly impose a load on the system. As a consumer, a solar customer looks like a customer who uses power in the morning, evening, and at night, but who turns everything off in the middle of the day, as illustrated by the dashed "Load on the Grid" line in Figure 3. Such a customer may come home unexpectedly in the middle of the day, turn on lights, a computer, and run an appliance, and produce a sudden spike in usage. But these load fluctuations are something the utility is well-prepared to serve on an aggregate basis, and the costs of such normal "stand by" service are included in the utility's regular rates.

Similarly, a solar customer may suddenly impose a demand on the system if a cloud temporarily covers the sun in the middle of the day. Again, however, this variability is manageable due to the small sizes and geographic diversity of solar DG systems – for example, at the time one PV system is being shaded, another will be coming back into full sunlight.

It is possible that, as solar penetration increases, the aggregate variability of all solar customers' electric output may add to the variability of the power demand that the utility must serve, and impose additional costs for regulation and operating reserves on the system operator. The costs of meeting this added variability is one of the factors considered in solar integration studies, such as the several such studies that APS has conducted.[12] These studies, as well as others done in other states,[13] show that such costs are low at the current level of solar DG penetration.[14]

Q20: Doesn't the utility incur costs to store the excess kWh produced by NEM systems, allowing the NEM customer to "bank" kWh which the customer uses later when the meter is rolling forward?

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[12] For example, see Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

[13] *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* (Battelle Northwest National Laboratory, March 2014); hereafter the "Duke Integration Study."

[14] For example, the Duke Integration Study calculates that, with 673 MW of PV capacity on the Duke utility systems in 2014, integration costs are about $0.0015 per kWh. See Table 2.5 and Figure 2.51.

A20: No. Net metering does not involve the storage of electricity, or of energy in any form. This idea is one of the common myths of net metering. Again, the NEM customer is both a consumer and generator of electricity. When the NEM customer is a generator, exporting power in excess of the onsite load, as a matter of physics that generation is immediately consumed by nearby customers. In no way is the power stored for later use. When the solar customer later consumes power from the grid – for example, after the sun sets – the power used is generated and transmitted by the utility at that time. The fact that NEM credits from exports are used to offset the costs of subsequent usage simply represents an accounting transaction – offsetting a credit with a debit on the customer's account by changing the direction that the meter is recording; it does not represent any actual use of the grid to "store" or "bank" electrons or energy.

E. Key Attributes of a DG Benefit-Cost Methodology

Q21: Please discuss the key attributes of a methodology to assess the benefits and costs of net metered DG resources.

A21: There are four key attributes:

1. **Analyze the benefits and costs from the multiple perspectives of the key stakeholders.** As discussed above, it is important that the Commission assess the benefits and costs of net metering from the perspectives of each of the major stakeholders – the utility system as a whole, participating NEM customers, and other ratepayers – so that the regulator can balance all of these important interests. Examining all of these perspectives is critical if public policy is to support customer choice and equitable competition between DG providers and the monopoly utility.

2. **Consider a comprehensive list of benefits and costs.** The location, diversity, and technologies of DG resources will require the analysis of a broader set of benefits and costs than, for example, traditional QF facilities installed under PURPA. Renewable DG projects produce power in many small (less than 1 MW) installations that are widely distributed across the utility system. The power is produced and consumed on the distribution system;[15] indeed, each net-metered DG project is generally associated with a

[15] It is possible that, at high penetrations, DG output to a distribution circuit could exceed the minimum load on the circuit, as has occurred at some locations in Hawaii where, for example, more than 15% of

load at least as large as the DG project's output,[16] which will limit the amount of power than is exported to the grid. For example, an important attribute of DG is its ability to serve loads without the use of the transmission system. Accordingly, an analysis of DG benefits should consider the avoided costs for transmission and distribution losses and capacity. Renewable DG also will avoid the costs associated with environmental compliance at marginal fossil-fueled power plants. On the cost side, the analysis should consider whether solar or wind DG will result in new costs to integrate these variable resources. The next section of this testimony discusses in more detail the specific benefits and costs that should be considered and that can be quantified.

3. **Analyze the benefits and costs in a long-term, lifecycle time frame.** The benefits and costs of DG should be calculated over a time frame that corresponds to the useful life of a DG system, which, for solar DG, 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 EE program, the company will look at the costs to build and operate the plant or the program over its useful life, compared to the costs avoided by not operating or building other resource options. The same time frame should be used to assess the benefits and costs of DG.

4. **Focus on NEM exports.** This testimony has explained how the retail rate credit for power exported to the utility is the essential characteristic of net metering. There would be no need for net metering if no power was exported, and without exports a DG customer appears to the utility grid as simply a retail customer with lower-than-normal consumption. From a legal perspective, PURPA requires the utility to interconnect with the DG customers and to allow the DG customer, at the customer's election, to use its privately-funded generation to serve its own load, on its own private property. It is only when the customer exports power to the utility – power to which the utility takes title at the meter and uses to serve other customers – that the question arises of how to compensate the DG customer for that power. This is the essential question that net metering answers, and the focus of the net metering analysis should be determining a credit for NEM exports that is fair to all affected parties.

IV. Specific Quantifiable Benefits and Costs

Q22: Please list and provide comments on the specific benefits and costs that should be quantified in the net metering methodology.

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customers on the islands of Oahu and Maui have installed solar. Such penetrations are not expected to be reached in Arizona for many years.

[16] Like many states, Arizona limits the size of NEM systems.

A22: There are several literature reviews or meta-studies which have reviewed the existing NEM/DG benefit/cost studies and have summarized the benefits and costs included in this growing literature:

- A 2013 literature review from the Vermont Commission.[17]
- The Rocky Mountain Institute's (RMI) 2013 meta-analysis of solar DG benefit and cost studies.[18]
- The New York State Energy Research and Development Authority (NYSERDA) recently conducted a literature review of NEM benefit/cost studies, with assistance from E3, in preparation for a NEM study in New York.[19]

Based on this literature, several recent studies have formulated recommended approaches to conducting such analyses, including the specific benefits and costs that should be considered.[20] These lists of benefits and costs are also consistent with the list, cited by Commissioner Little in his December 22, 2015 letter to this docket, that was assembled by Timothy James of the W.P. Carey School of Business at Arizona State University. Finally, cost effectiveness analyses of other types of demand-side programs also draw upon the same categories of benefits and costs, although the fact that DG is generation that can be exported to the grid introduces the new category of integration costs.

Based on the above sources and our prior experience with such studies, **Tables 2 and 3** list the specific benefits and costs, respectively, that should be quantified in the Commission's net metering methodology, along with brief comments on the methodology for the quantification of each specific category.

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[17] This literature review, as well as the report and analysis of net metering that the Vermont Commission completed, are available at http://publicservice.vermont.gov/topics/renewable_energy/net_metering .

[18] Rocky Mountain Institute (RMI), "A Review of Solar PV Benefit and Cost Studies" (July 2013), available at http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

[19] See the November 10, 2014 NYSERDA presentation listed at http://ny-sun.ny.gov/About/Stakeholder-Meetings.aspx .

[20] Interstate Renewable Energy Council and Rabago Energy, *A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation* (October 2013) and Synapse Energy Economics, *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits* (prepared for the Advanced Energy Economy Institute, September 2014).

1 **Table 2:** *Avoided Cost Benefits (for TRC, Societal, and RIM Tests)*

NEM Benefit Category	Description	Comments on Methodology
Avoided Energy	Change in the variable costs of the marginal system resource, including fuel use and variable O&M, associated with the adoption of DG.	Typically calculated from market energy prices (in deregulated markets), from production cost analyses (for regulated monopoly utilities), or from the energy costs of the proxy marginal resource. Calculation should be granular enough to calculate avoided energy costs of DG resources accurately. These energy costs should be adjusted for the appropriate energy losses (see below).
Avoided Generating Capacity	Change in the fixed costs of building and maintaining new conventional generation resources associated with the adoption of DG.	Forecast of marginal generation capacity costs calculated from market capacity prices (in deregulated markets), from the cost of the least expensive new capacity resource – typically a new combustion turbine peaker (for regulated monopoly utilities), or from the capacity cost of the proxy marginal resource. These capacity costs should be based on public, transparent data, should be adjusted for the appropriate losses (see below), and should reflect the capacity contribution of each type of renewable DG resource.
Avoided Line Losses	Change in electricity losses from the points of generation to the points of delivery associated with the adoption of DG.	Applies to both energy and generating capacity. Should be based on marginal line loss data and DG generation profiles. As a first approximation, marginal line losses are double the system average losses used in cost of service studies and tariffs.
Avoided Ancillary Services	Change in the costs of services like operating reserves, voltage control, and frequency regulation needed for grid stability associated with the adoption of DG.	These costs can be avoided if such reserves are procured based on loads that DG will reduce. Future DG technologies like "smart inverters" may provide services such as voltage support.
Avoided T&D Capacity	Change in costs associated with expanding/replacing/upgrading T&D capacity associated with the adoption of DG.	Based on marginal capacity costs to expand/replace/upgrade capacity on a utility's T&D system. Contribution of a DG resource to avoiding transmission or distribution capacity will depend on the contribution of DG to reducing peak loads on the transmission or distribution systems. This analysis will become more location-specific as one moves to lower voltages on the distribution system, where distribution feeders will peak at different times.
Avoided Environmental Costs	Change in costs associated with mitigation of SO_x, NO_x, and PM-2.5 emissions or with waste disposal costs (e.g. coal ash) due to the change in production from each IOU's marginal generating resources as a result of the adoption of DG generation.	Can be included in the Avoided Energy component.
Avoided Carbon Emissions	Change in costs to mitigate CO_2 or equivalent emissions due to the change in production from each IOU's marginal generating resources associated with the adoption of DG.	Based on estimates of the value of carbon emission reductions from utility integrated resource plans (IRPs) or from regulatory agencies with jurisdiction over such emissions. Such reductions can have quantifiable value to ratepayers through avoiding direct emission costs (as in cap & trade

		markets) or through the costs of resource choices intended to reduce carbon emissions (such as the replacement of coal with natural gas or the construction of carbon-free nuclear or renewable capacity.
Fuel Hedge	Costs to lock in the future price of fuel to match the fixed-price attribute of renewable DG.	Can be approximated through the use of forward natural gas prices to forecast future avoided energy costs, plus the transaction costs of such hedging.
Market Price Mitigation	Reduction in energy and capacity wholesale market prices as a result of lower demand resulting from DG adoption.	This benefit of demand-side resources has been quantified in certain U.S. markets (New England and California).
Avoided Renewables	Reduction in above-market generation costs associated with the utility's acquisition of renewable resources, if DG will contribute to meeting the utility's renewable procurement goals.	This benefit will apply to the extent that renewable DG meets a state goal that otherwise would be met with utility-owned or contracted resources.
Societal Benefits (for only the Societal Test)	Benefits for citizens of the utility's service territory or state that are not reflected directly in customer's energy costs.	Lower environmental costs from... • Damages due to climate change • Consumption or withdrawal of scarce water resources • Land use impacts Health benefits from.... • Lower criteria air emissions Economic benefits from... • Fewer power outages • Greater local economic activity

Table 3: *Costs of DG Programs (for TRC and RIM Tests)*

NEM Cost Category	Description	Comments on Methodology
For TRC Test...		
DG Resource	Capital and O&M costs of the DG resource.	
Integration	Increased costs for regulation and operating reserves to integrate variable renewable DG resources.	Integration costs should be those attributable to DG that are incremental to the costs to meet load variability.
Administrative / Interconnection	Utility costs to administer the NEM/DG program, as well as utility costs to interconnect DG resources that are not paid by the DG customer.	Should include the incremental costs associated with net metering above those required for regular billing, as well as other administrative costs. Interconnection costs should not include such costs if they are paid by the DG customer itself.
For RIM Test...		
Lost Revenues	Bill credits provided to NEM customers for exported energy.	Will vary depending on the tariff under which the DG customer takes service.
Integration	Same as above	
Administrative/ Interconnection	Same as above	

Q23: Do you have any general observations on these specific categories of benefits and costs?

A23: Yes. First, all of the above categories of benefits and costs are quantifiable, and have been quantified in other NEM or DG benefit/cost studies.

Second, the quantification of these benefits may require data and/or calculations that the utilities may not produce today in the normal course of business. For example, not all utilities calculate marginal line losses or marginal T&D capacity costs, although many do, and there are well-accepted techniques to perform these calculations.

Third, to the extent that studies of relatively complex issues – such as solar or wind integration costs – have yet to be performed, reasonable values for these costs can be derived from such studies performed for other utilities.

Finally, if there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that category. For example, although the costs for mitigating carbon emissions are uncertain, the IRPs of the Arizona utilities make clear that these costs are not zero for ratepayers, because the utilities are planning today, and spending money today, to reduce their carbon emissions through the replacement of older coal plants with new natural gas-fired generation. For example, the selected case in the 2014 APS IRP includes reductions in the utility's fleet of aging coal plants, and their replacement with new gas-fired and renewable resources. The APS 2014 IRP is based on CO_2 emissions costs of $13 per ton in 2020, escalating to almost $16 per ton in 2029.[21]

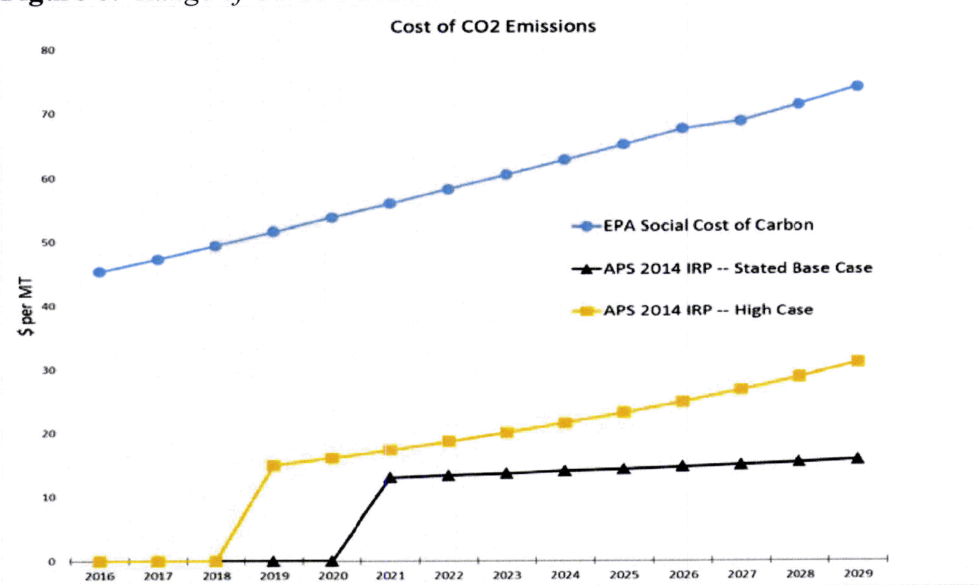
Further, the EPA's proposed regulations of greenhouse gas (GHG) emissions from power plants under Section 111(d) of the Clean Air Act indicate that the federal government may regulate such emissions based on the administration's

[21] APS 2014 IRP, at Figure 15.

social cost of carbon (SCC) values. The EPA proposal increases the certainty that the utilities will incur significant future costs for reducing carbon emissions.

All of the above considerations underscore the point that a reasonable assumption for future carbon costs is not zero, but should consider a range of possible future mitigation costs. Such a range is shown in **Figure 6**, with carbon costs varying from those that APS has assumed in its 2014 IRP up to, in the high case, the federal SCC values.

Figure 6: *Range of Carbon Costs*



V. New Benefit-Cost Study of DG in Arizona: APS

Q24: Have you performed a benefit-cost study of solar DG for an Arizona utility?

A24: Yes, I have. **Exhibit 2** to this testimony is a new study of the benefits and costs of solar DG on the APS system which expands and updates the study Crossborder Energy conducted in 2013. This study follows the general approach discussed above, including the use of multiple perspectives, a comprehensive list of benefits and costs, and a long-term analysis that focuses on generation exports.

Q25: What are the key conclusions of the APS study?

A25: The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** for APS, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

2. There is a **balance between the costs and benefits of residential DG** for both participants and non-participants, as shown by the results for the Participant and Ratepayer Impact Measure tests.

3. **Significant rate design changes for residential DG customers**, such as requiring solar DG customers to take service under the ECT-2 TOU rate with demand charges, **would upset this balance**.

3. The **benefits of DG significantly exceed the costs in the commercial market.** Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the APS system. Removing rate design barriers such as excessive demand charges would be one way to assist the commercial solar market in Arizona.

4. The benefits of solar DG in APS's service territory are **higher for west-facing systems.** If there is a concern about the cost of DG to non-participating ratepayers, particularly for residential customers, an important step to address such a concern would be to encourage and incentivize west-facing systems.

5. The analysis indicates **lower costs of solar DG to non-participants under APS's existing residential time-of-use (TOU) rates**. Lost revenues under APS's existing residential TOU rates are about one cent per kWh lower than under its flat rate (Schedule E-12). Thus, encouraging greater use of TOU rates also will improve the cost-effectiveness of solar DG.

VI. Application of the Benefit-Cost Methodology to Determine Rates

Q26: How should the analysis which you have outlined above be used to determine the rates and charges which will apply to NEM customers?

A26: Any new charge or rate design applicable to net-metered customers should be tested to ensure that, after it is applied, DG will remain a viable economic proposition for participating ratepayers, the utility system, and the state as a whole, while not imposing undue upward pressure on the rates of non-participants. Such a balancing test should use a long-term benefit-cost analysis from multiple perspectives, because DG is an important long-term resource whose economics should be assessed over its full economic life, in the same way that other resource options are assessed.

Q27: Are there important lessons from other states in terms of how the results of a cost-benefit analysis of NEM may differ among different types and classes of customers?

A27: Yes. The impacts of net metering on non-participating ratepayers will vary significantly across customer classes. For example, the costs of NEM are typically lower for commercial and industrial (C&I) classes than for residential customers, for several reasons. First, C&I rates tend to be lower than residential rates. Second, the solar DG systems of C&I customers tend to export less power to the grid than residential systems, because the diurnal load profile of C&I customers often is a better match for the profile of solar output and because the DG systems installed by C&I customers typically are smaller relative to the size of the on-site load. Finally, rate design has a major impact on the bill savings that NEM customers can realize, and thus on the lost revenues that are the major cost of NEM for non-participating ratepayers. C&I rate designs often recover a significant portion of the utility's costs through monthly customer and demand charges that are difficult for C&I customers to avoid. Cost studies adopted by the California PUC have demonstrated that demand charge structures actually overcharge solar customers relative to the costs that they impose on the system, and undervalue the peaking capacity that solar DG provides. As a result, SCE and other California utilities have designed rate options with reduced demand charges but correspondingly higher volumetric time-of-use rates, and make those rate options available to C&I customers who install solar.[22]

Q28: Should customer-generators be placed into their own rate classes?

A28: No. Customer-generators should not be placed into a separate class without sufficient data to justify distinct treatment. It cannot be assumed that, after installing DG, customers will become significantly different than other customers in the class. In general, data from many states show that adding solar tends to change a larger-than-average customer into a smaller-than-average one, but both pre-and post-solar customers are well within the range of sizes typical of the residential class.[23]

Q29: If the Commission's analysis finds that there is a cost shift from customer-generators to non-participating ratepayers that is large enough to require mitigation, what are the recommended rate design approaches to remedying this problem?

A29: There are several. Impacts on non-participants are most likely to be a concern in the residential market, because residential solar systems export a higher percentage of their output and because most of the residential cost of service is

[22] See California PUC Decision No. 14-12-080, adopting Option R rates for PG&E after a fully-litigated proceeding; Decision No. 13-03-031 (March 21, 2013), at p. 31, discussing Option R rates for Medium and Large Power customers; and CPUC Decision No. 09-08-028 (August 20, 2009), at p. 22, first implementing Option R rates for SCE's Medium and Large Power customers who install solar.

[23] In 2014, the Colorado PUC has held workshops on net metering issues. Data from those workshops showed that the typical residential customer in Colorado who installs solar tends to have greater usage than an average customer, with an average monthly pre-solar bill of $126 compared to the average residential bill of $77 per month. After adding solar, the typical solar customer's bill drops to $50 per month. This information is based on data from solar customers on the Public Service of Colorado system. See "On-Site Solar Industry Answer to Questions set forth in Attachment A of Commission Decision No. C14-0776-I," filed July 21, 2014 in Colorado PUC Docket No. 14M-0235E, at pp. 8-9.

In 2014, the Utah Public Service Commission reached a similar conclusion in rejecting a proposal from Rocky Mountain Power to impose a net metering facilities charge. In Utah, the typical residential customer uses 500-600 kWh per month, with net metered customers falling at the low end of this range at 518 kWh per month. The Utah commission concluded that "[t]hese facts undermine PacifiCorp's reasoning that net metered customers shift distribution costs to other residential customers in a fashion that warrants distinct rate treatment." See Utah PSC, Order issued August 29, 2014 in Docket No. 13-035-184, at p. 62.

recovered through volumetric rates. The preferred rate design solutions are the following:

- Encourage increased adoption of **time-of-use rates** that align rates more closely to the changes in the utility's costs over the course of a day.[24]

- Adopt a monthly **minimum bill** to recover customer-related costs, thus ensuring that all customers make a minimum contribution to the costs of the utility infrastructure that serves them.

- Remove **public benefit charges** from the NEM export rate, so that all customers contribute to these public purpose programs on the equitable basis of the power they take from the utility system.[25]

These solutions are preferable for the following reasons:

- **Address the central equity issue.** Minimum bills, for example, ensure that all customers make a minimum contribution to the utility infrastructure that serves them. The minimum bill can be set to cover the utility's customer-related costs (for metering, billing, and customer account services) which clearly do not vary with usage. In this way, they address directly the issue of equity between participating and non-participating ratepayers by ensuring that all customers contribute equally to such costs. Similarly, it is equitable for all customers to contribute to public purpose programs on the same basis, that is, based on the amount of service which they take from the utility system.

- **Consistent with cost causation.** TOU rates align rates more closely with the utility's underlying costs than do flat volumetric rates. A minimum bill can be set to assure recovery from all customers of customer-related costs which do not vary with usage. Thus, both TOU rates and minimum bills are consistent with cost causation principles.

- **Encourages customer choice.** Because a minimum bill only imposes a floor on the customer's bill and does not apply if usage remains above the minimum bill level, it provides the greatest scope for customers to impact their energy bills by exercising their free-market choice to participate in self-generation, energy efficiency, or demand response. Similarly, TOU rates send more accurate price signals to customers concerning both the

[24] This can include on-peak volumetric rates that recover capacity-related costs. Residential TOU rates should be kept simple and promoted through outreach and education programs, to ensure customer acceptance. Residential demand charges should be avoided due to their complexity, lack of time sensitivity, and unfamiliarity for residential customers. California has mandated that, once the state's 5% NEM cap is reached, succeeding NEM customers must elect a TOU rates.

[25] California and Nevada have implemented this modification to NEM export rates.

value of their DG output and when it is best to either consume or conserve energy.

- **Customer acceptance.** California, which has the nation's largest distributed solar market, has adopted a $10 per month residential minimum bill for the large electric utilities in that state, and the minimum bill was recently increased in Hawaii, where solar penetration is far higher than any other state. In contrast, attempts to implement monthly fixed charges on solar customers have not been well-received in other states, and have been perceived as efforts to tax solar production such that it would no longer be economic.[26] In essence, minimum bills are perceived as a fair balance between allowing customer choice and ensuring that all customers make an equitable contribution to the costs of utility infrastructure. Significantly, although California and Nevada recently issued very different decisions on net metering, both commissions rejected proposals to apply demand charges to residential solar customers due to concerns with customer acceptance.[27]

- **Non-discrimination.** Many states, including Arizona, have statutory prohibitions against undue discrimination in the design of utility rates.[28] If fixed charges are raised for all residential customers, there can be adverse bill impacts on all low-usage customers, including low-income ratepayers. A minimum bill is more likely to avoid such problems, as it will apply to a relatively small number of non-net-metered customers.

- **Avoid competitive bypass.** A minimum bill can address impacts on non-participants by providing DG vendors with a signal to reduce the sizing of DG systems to keep customers above the minimum bill level, thus reducing the costs of net metering for other ratepayers. This still allows scope for customer choice of DG for usage above the minimum bill level. In contrast, if a fixed charge on residential DG is set too high, as DG and on-site storage technologies continue to develop and as their costs continue to fall, the response of consumers ultimately may be to "cut the cord" completely from utility service, as has happened with landline telephone service in many areas. In my opinion, such a result would be unfortunate, because the utility grid would lose important benefits that DG and on-site storage could provide for all ratepayers, and DG customers would lose the still-important benefits of interconnection to the grid.

[26] For example, Idaho PUC, Final Order No. 32846 in Case No. IPC-E-12-27 (July 3, 2013), at pp. 3-5.
[27] See PUCN December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042, at p. 91, also CPUC Decision 16-01-044, at pp. 75 and 79.
[28] Ariz. Const. Article XV, § 12.

VII. Utility-scale and Rooftop Solar

Q30: It is sometimes argued that, because utility-scale solar benefits from economies of scale and thus has lower capital costs than smaller rooftop systems, utilities should encourage utility-scale solar to the exclusion of rooftop systems. Do the capital cost differences between utility-scale and rooftop solar represent the relative costs to ratepayers for these resources?

A30: No, they do not, because rooftop and utility-scale solar systems do not provide ratepayers with the same product. Rooftop solar provides a retail product, while utility-scale solar supplies a wholesale product. The majority of the output of a rooftop solar facility provides power directly to end-use retail loads, behind the meter, where it displaces retail power from the utility. A minority of power is exported to the distribution grid, where it immediately serves neighboring loads, also displacing retail power from the utility. In most states, the DG customer is compensated for this power at the retail rate, through net energy metering. In contrast, utility-scale solar projects supply wholesale power to the utility, delivering power to the high-voltage transmission system and competing with other sources of wholesale power.

Q31: Explain how to compare the differences between these products.

A31: The retail, rooftop product has been delivered to load, whereas the wholesale, utility-scale product has not. Thus, for an apples-to-apples comparison between the two resources, one must add to the cost of utility-scale solar, at a minimum, the marginal costs associated with delivering this power to the same customers that can be served by rooftop solar. The correct rate to use in this comparison is the marginal cost for transmission and distribution which the utility avoids if rooftop solar supplies a customer and his neighbors, thus avoiding the need for the utility to provide delivery service from a more remote wholesale generation source.

Although the locational difference between utility-scale and rooftop solar is the most apparent distinction between these two types of solar, there are other differences that bear on the comparative value of these resources, including the value of these resources in meeting the demand for renewable power. Solar generation contributes to meeting Renewable Portfolio Standard ("RPS") requirements in many states. Each state with an RPS has its own unique rules for counting a renewable resource's contribution to RPS requirements. For example, some states, such as Arizona, have set-asides for renewable DG; others, like Nevada, have adopted multipliers for DG in determining DG's compliance with RPS needs. In addition, rooftop solar output reduces the utilities' sales, and thus further lowers RPS requirements (and ratepayer costs) which are tied to an increasing percentage of sales.

Further, rooftop solar provides additional societal benefits compared to utility-scale solar, including greater economic benefits for the communities which have a vibrant local solar installation industry and the resiliency benefits of local power production. These are quantified in the accompanying study on APS. Rooftop solar also 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.

Q32: Are there any other important policy reasons why a state should maintain a supportive environment for customer-sited, distributed renewable generation?

A32: Yes. Rooftop solar and other renewable distributed energy technologies allow customers 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.** Customer-owned or customer-sited generation brings new sources of capital for clean energy infrastructure. Given the magnitude and urgency of the task of moving to clean sources of energy, expanding the pool of capital devoted to this task is essential.

- **New Competition.** Rooftop solar provides a competitive alternative to the utility's delivered retail power. This competition can spur the utility to cut costs and to innovate in its product offerings. With the widespread availability in the near future of customer-sited storage paired with rooftop solar, energy efficient appliances, and load management technologies, this competition will only intensify, given that the combination of solar and storage in the future may offer an electric supply whose quality and reliability is comparable to utility service.

- **Grid Services.** With deployment of smart inverters in 2016, rooftop solar systems can provide voltage services, reactive power and other grid services. In addition, by reducing load on individual circuits, rooftop solar systems reduce thermal stress on distribution equipment, thereby extending its useful life and deferring the need to replace it. All of these additional values are difficult to quantify because there are not currently markets for these services, and utilities do not have an incentive to procure these types of services from third-party providers.

- **Enhanced Reliability and Resiliency.** Renewable distributed generation resources are installed as thousands of small, widely distributed systems and thus are highly unlikely to fail at the same time. Furthermore, the impact of any individual outage at a DG unit will be far less consequential, and less expensive for ratepayers, than an outage at a major central station power plant. DG is located at the point of end use, and thus also reduces the risk of outages due to transmission or distribution system failures. Most electric system interruptions result from weather-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

- **High-tech Synergies.** Rooftop solar appeals to those who embrace the latest in technology. Solar has been described as the "gateway drug" to a host of other energy-saving and clean energy technologies. Studies have shown that solar customers adopt more energy efficiency measures than other utility customers, which is logical given that it makes the most economic sense to add solar only after making other lower-cost efficiency improvements to your premises. Further, with net metering, customers retain the same incentives to save energy that they had before installing solar. These synergies will only grow as the need to make deep cuts in carbon pollution drives the increasing electrification of other sectors of the economy, such as transportation.

- **Customer Engagement.** Customers who have gone through the process to make the long-term investment to install solar learn much about their energy use, about utility rate structures, and about producing their own energy. Given their long-term investment, they will remain engaged going forward. There is a long-term benefit to the utility and to society from a more informed and engaged customer base, but only if these customers remain connected to the grid. As we have seen recently in Nevada, this positive customer engagement can turn to customer "enragement" if the utility and regulators do not accord the same respect and equitable treatment to customers' long-term investments in clean energy infrastructure that is provided to the utility's investments and contracts. Emerging storage and energy management technologies may allow customers in the future to "cut the cord" with their electric utility in the same way that consumers have moved away from the use of traditional infrastructure for landline telephones and cable TV. Given the important long-term benefits that renewable DG can provide to the grid if customer-generators remain connected and engaged, it is critical for regulators and utilities to avoid alienating their most engaged and concerned customers.

- **Self-reliance.** The idea of becoming independent and self-reliant in the production of an essential commodity such as electricity, on your own property using your own capital, has deep appeal to Americans, with roots in the Jeffersonian ideal of the citizen (solar) farmer.

The benefits of choice listed above are difficult to express in dollar terms; however, all are strong policy reasons for ensuring that the development of clean energy infrastructure includes policies which sustain a robust market for rooftop solar.

Q33: Does this conclude your prepared direct testimony?

A33: Yes, it does.

Exhibit 1

Curriculum Vitae of
R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

   - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

   - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
   b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

   - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

   - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

   - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

   - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

   - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

   - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
 b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

- *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

- *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
 b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
 b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

- *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
 b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

- *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).
https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

    - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

- *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

    - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

    - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014:

http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443

June 20, 2104:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

- *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

EXHIBIT 2

Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (2016 Update)

R. Thomas Beach
Patrick G. McGuire

February 25, 2016

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

This report provides a new benefit-cost analysis of the impacts of solar distributed generation (DG) on ratepayers in the service territory of Arizona Public Service (APS). The Arizona Corporation Commission has initiated a generic investigation in Docket No. E-00000J-14-0023 to review net energy metering (NEM) issues and to help inform future Commission policy on the value that DG installations bring to the grid. On October 20, 2015, the Commission ordered that an evidentiary hearing be held in this generic docket; among the issues to be heard are the value and costs of DG related to Arizona Public Service Company's (APS) provision of service to DG and non-DG customers. This report contributes to the Commission's investigation by presenting a new study of the benefits and costs of solar DG in the APS service territory. This study builds upon and updates the study that Crossborder Energy presented at a series of technical conferences on DG valuation that APS held in 2013,[1] as well as our presentation to the workshop that the Commission held on May 7, 2014.

This report provides a comprehensive benefit-cost analysis of demand-side solar in APS's service territory. This analysis has the following key attributes:

1. **Multiple perspectives.** Examine and balance the benefits and costs of solar DG from the perspectives of all of the key stakeholders – DG customers, other ratepayers, and the system and society as a whole – because all of these stakeholders constitute the public interest in DG development. As a result, we examine the benefits and costs of solar DG using the full set of cost-effectiveness tests for demand-side resources that commonly are used in the utility industry.
2. Consider a **comprehensive list of benefits and costs**.
3. Use **a long-term, life-cycle analysis** that covers the useful life of a solar DG system, which is at least 20 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side.
4. Focus on **NEM exports**, because it is those exports that differentiate DG customers from other types of demand-side resources.

This report relies on data from APS's 2014 Integrated Resource Plan (2014 IRP),[2] which provides the long-term data set that is the starting point for this analysis. We have supplemented the 2014 IRP with data from discovery, from prior studies of the value of DG and renewable generation in Arizona and the western U.S., and from current data from the regional gas and electric markets in which APS operates. Our approach to valuing solar DG also draws upon relevant analyses that have been conducted in other states, including the "public tools" for evaluating net metered DG that have been developed in Nevada and California.[3]

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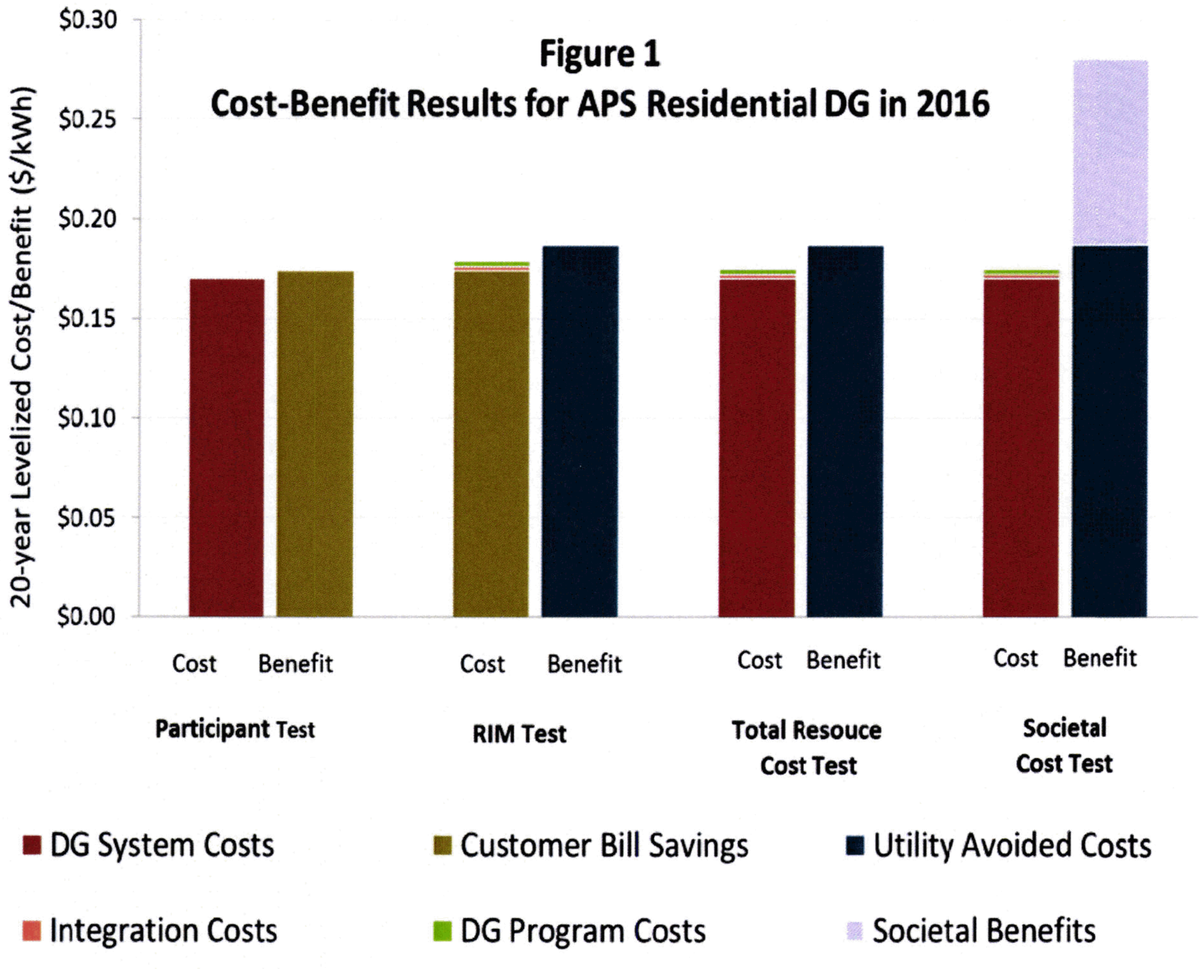
[1] Crossborder Energy, "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service" (May 8, 2013), available at http://www.seia.org/research-resources/benefits-costs-solar-distributed-generation-arizona-public-service.

[2] The APS 2014 IRP is available at https://www.aps.com/en/ourcompany/ratesregulationsresources/resourceplanning/Pages/resource-planning.aspx.

[3] See the Public Utilities Commission of Nevada's (PUCN) 2014 net metering study at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study. The California Public Utilities Commission's Public Tool is described and is available at http://www.cpuc.ca.gov/General.aspx?id=3934.

The costs of solar DG for APS's non-participating ratepayers are principally the lost revenues for the utility 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). To determine these costs, we calculate 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, net of the existing monthly installed capacity fee assessed on DG customers. We use an assumed rate escalation based on the future rates estimated in the 2014 IRP, plus the rate of inflation for the customer and delivery costs not covered in the IRP. Finally, on the cost side, we also include an estimate of APS's costs to integrate solar DG into the grid.

Our work concludes that the benefits of residential DG on the APS system are in balance with the costs, such that new residential DG customers will not impose a burden on APS's ratepayers. The following figure and table summarize the results of our application of the primary cost-effectiveness tests to residential solar DG on the APS system.



For APS's commercial customers, the benefits of DG significantly exceed the costs, as shown below.

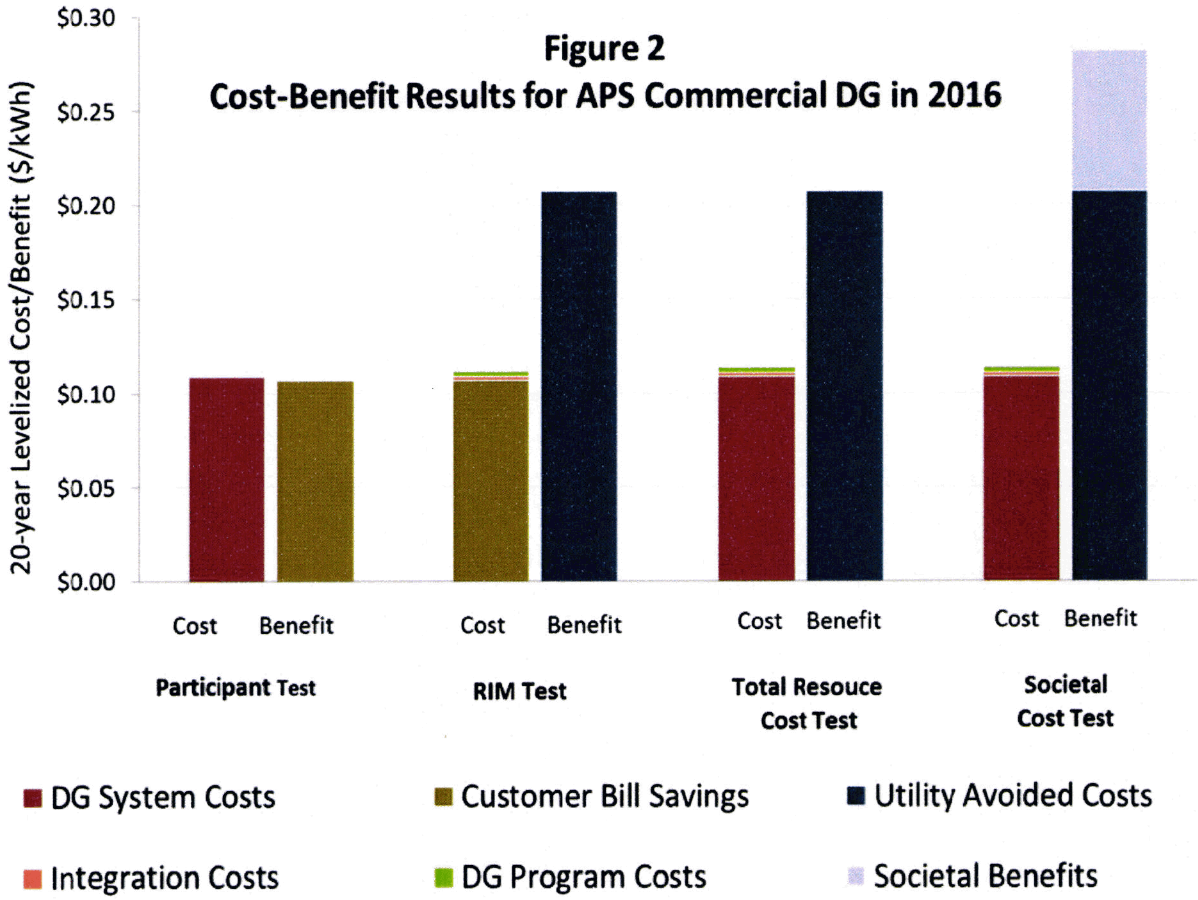


Table 1: *Benefits and Costs of Solar DG on the APS System (20-yr levelized cents/kWh)*

	Orientation	Residential	Commercial
Benefits			
Direct Benefits	South	15.5	18.0
	West	21.8	23.4
	Average	18.7	20.7
Societal Benefits	All	9.3	7.5
Total Benefits	South	24.8	25.5
	West	31.1	30.9
	Average	28.0	28.2
Participant Costs			
Median		17.0	10.9
Range		12 to 24	9 to 14
Non-Participant Costs		17.9	11.2

The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** for APS, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

2. There is a **balance between the costs and benefits of residential DG** for both participants and non-participants, as shown by the results for the Participant and Ratepayer Impact Measure tests.

3. **Significant rate design changes for residential DG customers**, such as requiring solar DG customers to take service under the ECT-1R or ECT-2 TOU rates with demand charges, **would upset this balance**.

3. The **benefits of DG significantly exceed the costs in the commercial market**. Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the APS system.

4. The benefits of solar DG in APS's service territory are **higher for west-facing systems.** If there is a concern about the cost of DG to non-participating ratepayers, particularly for residential customers, an important step to address such a concern would be to encourage and incentivize west-facing systems.

5. The analysis indicates **lower costs of solar DG to non-participants under APS's existing residential time-of-use (TOU) rates**. Lost revenues under APS's existing residential TOU rates are about one cent per kWh lower than under its flat rate (Schedule E-12). Thus, encouraging greater use of TOU rates also will improve the cost-effectiveness of solar DG.

1. Methodology

Solar DG is a long-term resource for the APS system. New solar DG systems will provide benefits for the APS service territory for the next 20 to 30 years. Thus, our analysis develops 20-year levelized benefits and costs for solar DG on the APS system. We evaluate the long-term benefits and costs of solar DG from multiple perspectives, using each of the major cost-effectiveness tests widely used in the utility industry.[4] Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 2** below ("+" denotes a benefit; "-" a cost).

Table 2: *Demand-side Cost/Benefit Tests*

Perspective (Test)	DG Customer (Participant)	Other Ratepayers (RIM)	Total Resource Cost to Utility or Society (TRC or Societal)
Capital and O&M Costs of the DG Resource	—		—
Customer Bill Savings or Utility Lost Revenues	+	—	
Benefits (Avoided Costs) -- Energy -- Generating Capacity -- T&D, including losses -- Reliability/Resiliency/Risk -- Environmental / RPS		+	+
Federal Tax Benefits	+		+
Program Administration, Interconnection & Integration Costs		—	—

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. First, the program should be a net benefit as a resource to the utility system or society more broadly – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of solar DG systems to their benefits to the utility system and society as a whole. Second, the DG program will need to pass the Participant test if it is to attract customers to make long-term investments in DG systems. Finally, the Ratepayer Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all parties will benefit from the program. However, it is a test that measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC and Societal tests).

Data. The starting point for the data needed to perform full 20-year benefit/cost assessments is the utility's 2014 IRP, as a consistent set of long-term resource cost data that can be used to determine both the benefits and costs of solar DG. For example, we have used the natural

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[4] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

gas forecast from the 2014 IRP, even though current gas prices are lower than was forecasted in 2014, and we have also used the long-term escalation in retail rates indicated by the 2014 IRP. If we were to update the natural gas forecast to use today's prices, we would also have to reduce correspondingly the long-term escalation in retail rates. We indicate in the report where we have supplemented 2014 IRP data with other information from discovery in this case, from prior DG studies in Arizona,5 and from other reports on the impacts of the growing demand for, and supply of, renewable generation in the western U.S.

Benefits. Several of the most important (and beneficial) characteristics of DG are 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 2014 IRP combines with EE and DR to meet APS's resource needs in the near term and will help to defer the need for larger-scale resources in the long-run. The 2014 IRP finds that APS does not need new resources until 2017, and will not build new, large-scale, fossil resources until 2018. However, the 2014 IRP also shows continued growth both in energy efficiency and demand response programs and in distributed solar resources between 2014 and 2019, such that new demand-side resources developed in 2014-2019 will contribute 986 MW to meeting APS's peak demands by 2019.[6] As a result, solar DG, along with energy efficiency and demand response, contributes to deferring any new power plants until 2018, and solar DG installed before 2018 has greater value than just avoiding short-term energy costs.

We have included a number of additional benefits of DG that are often overlooked, including the following direct benefits that reduce ratepayer costs:

- **Fuel hedging benefits.** Renewable generation, including solar DG, reduces a utility's exposure to volatility in fossil fuel prices.

- **Price mitigation benefits.** Solar DG reduces the demand both 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.

- **Avoided 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. APS recognizes this avoided capacity reserve cost in calculating the benefits of peak demand reductions from other types of demand-side resources.[7]

In addition, solar DG also provides quantifiable societal benefits to the citizens in APS's service territory. These include important environmental benefits, such as reduced emissions of carbon and criteria air pollutants, and lower use of scarce water resources. The 2014 IRP includes the data needed to quantify the reduced emissions of these pollutants as well as the water savings. We draw upon several recent quantifications of these societal benefits. We also include the additional societal benefits of stimulating local economic activity and enabling customers to enhance the reliability and resiliency of their electric service.

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5 For example, R.W. Beck (for APS), "Distributed Renewable Energy Operating Impacts and Valuation Study" (January 2009), hereafter, the "R.W. Beck Study," and SAIC Energy, Environmental and Infrastructure LLC (for APS), "2013 Updated Solar PV Value Report" (May 2013), hereafter, the "SAIC Study."

6 2014 IRP, at page 8 (Table 1) and 20.

7 See APS response to TASC Data Request No. 2.1(j).

One of the reporting requirements of the 2014 IRP is a summary of the benefits of renewable generation on the APS system over the 2014-2028 IRP forecast period. These are shown below, from Table 27 of the 2014 IRP. We use APS's reported natural gas savings from renewables to estimate the avoided energy costs associated with solar DG, and we also use the avoided emissions from this conserved natural gas to quantify some of the environmental benefits associated with these clean energy resources.

TABLE 27 - RENEWABLE ENERGY BENEFITS

	TOTAL RENEWABLE			AVOIDED EMISSIONS						
	Peak Capacity (MW)	Energy (GWh)	Avoided Gas Burn (BCF)	CO_2 (Metric Tons)	SO_2 (Tons)	CO (Tons)	NOx (Tons)	PM10 (Tons)	HG (Lbs)	Water Usage (Acre Feet)
2014	701	3,182	23	1,280,869	7	162	146	40	6	3,066
2015	744	3,355	25	1,350,452	8	171	153	42	6	3,233
2016	775	3,492	26	1,405,597	8	178	160	43	7	3,365
2017	786	3,526	26	1,419,337	8	180	161	44	7	3,398
2018	798	3,566	26	1,435,664	8	182	163	44	7	3,437
2019	810	3,607	27	1,452,019	8	184	165	45	7	3,476
2020	863	3,934	29	1,583,558	9	200	180	49	7	3,791
2021	911	4,268	31	1,718,118	10	217	195	53	8	4,113
2022	960	4,656	34	1,874,185	10	237	213	58	9	4,486
2023	1,052	5,323	39	2,142,811	12	271	243	66	10	5,129
2024	1,095	5,706	42	2,296,957	13	291	261	71	11	5,498
2025	1,139	6,138	45	2,470,889	14	313	281	76	12	5,915
2026	1,157	6,230	46	2,507,865	14	317	285	77	12	6,003
2027	1,168	6,270	46	2,523,886	14	319	287	78	12	6,042
2028	1,256	6,915	51	2,783,504	15	352	316	86	13	6,663
2029	1,268	6,944	51	2,795,214	16	354	318	86	13	6,691
		TOTAL	**567**	**31,040,924**	**173**	**3,927**	**3,527**	**959**	**145**	**74,305**

Costs. The Participant Test uses the costs of solar DG for the participating customers who install solar systems. These are the costs for the systems themselves (offset by the federal investment tax credit), financing, maintenance, and periodic inverter replacement. The cost of DG systems can vary based on size, installation costs, financing terms, and output.

In the RIM Test, the costs of solar DG for non-participating ratepayers are principally the revenues which APS loses from customers serving their own load with DG. To these lost revenues we add an estimate of the solar integration costs which APS will incur to incorporate these resources into its system, as determined in APS's most recent solar integration study. We also add costs for the utility to interconnect DG customers and to administer the DG program.

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 least 20 years. Accordingly, we calculate the benefits and costs of DG over a 20-year period in order to capture fully the value of these long-term resources, and we express the results as 20-year levelized costs using the same 7.2% per year discount rate that APS assumed in its 2014 IRP.[8]

8 2014 IRP, at Table 21 (APS' after-tax weighted average cost of capital).

2. Direct Benefits of Solar DG

a. Energy

APS's 2012 resource plan makes clear that the utility's incremental sources of generation in the future will principally be flexible natural gas-fired generation:

> *The conclusion of this [IRP] process was clear: low natural gas prices combined with the cost of environmental regulations and increases in self-dispatching solar generation will favor highly flexible natural gas resources over traditional baseload resources.*[9]

The plan shows load growth of about 3% per year, offset by continued growth in customer-sited DG, energy efficiency, and demand response resources. To the extent that there are variations from the IRP forecast in future loads or demand-side resources, APS's need for marginal gas-fired generation will change correspondingly. Thus, solar DG avoids marginal gas-fired generation on the APS system. Because APS has met and exceeded current Renewable Energy Standard requirements in Arizona, if solar DG resources do not materialize, there is no need to replace them with other utility-scale renewable generation, so DG does not avoid utility-scale renewables.

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 have used the gas savings from renewable resources that APS reports in Table 27 of the IRP (see above), times the 2014 IRP forecast of APS's burnertip cost of gas at its power plants.[10] We understand that the IRP's natural gas forecast was based on forward market natural gas prices, so it represents a cost of gas that APS could fix for the next 20 years.[11] This captures some of the fuel price hedging benefit of renewable DG, but, as discussed below, it does not capture the hedging costs which a utility such as APS can avoid when increases in renewable DG reduce the utility's gas burns and thus its exposure to volatile fossil fuel prices.

We also include APS's 2014 IRP forecast of greenhouse gas (GHG) allowance costs ($13 per metric ton, starting in 2021) as an adder to the gas price forecast,[12] 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.[13] With these inputs, our forecast of APS's avoided energy costs for solar DG is a 20-year levelized value of 6.3 cents per kWh, in 2014 dollars.

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[9] 2014 IRP, at p. viii.

[10] These natural gas savings are for the entire APS portfolio of renewable resources, which includes wind, biomass, and geothermal resources that have a baseload profile, as well as peaking solar resources. Thus, these gas savings may be low for solar DG, because peaking solar resources avoid the less-efficient, higher-heat-rate gas-fired generation that operates during the peak afternoon hours.

Further, 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. We assume that these benefits are included in APS's modeling of the energy savings from renewables, in Table 27 of the IRP.

[11] 2014 IRP, at p. 52.

[12] 2014 IRP, at Figure 15.

[13] 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.

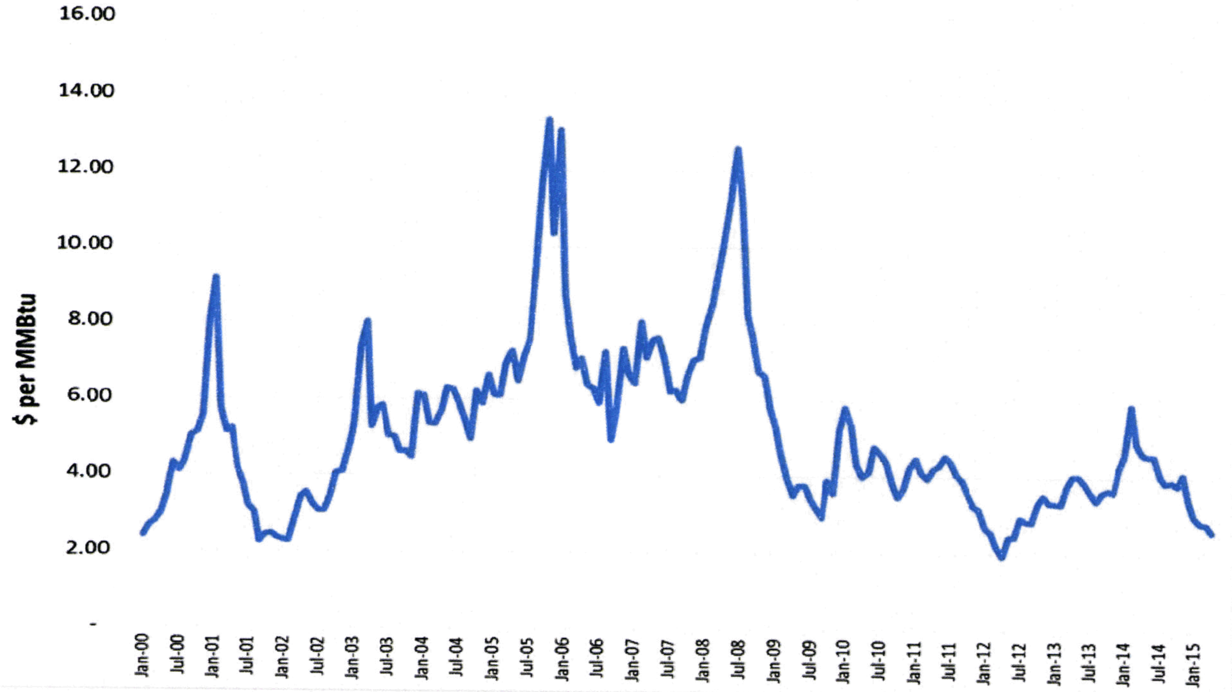
Table 3: *APS Avoided Energy Costs*

Avoided Energy Costs *(20-year levelized c/kWh, 2016 $)*	
Period	Avoided Costs
2016-2035	6.2

b. Fuel hedging costs

Renewable generation, including solar DG, reduces a utility's exposure to volatility in fossil fuel prices, thus mitigating the impacts on ratepayers of periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 3** below.[14]

Figure 3: Henry Hub Natural Gas Market Prices



Renewable generation also hedges against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as is occurring today with the drought in California and long-term, drier-than-normal conditions elsewhere in the West. In 2014, the rapidly increasing output of solar projects in California made up for 83% of the reduction in hydroelectric output in the state due to the multi-year drought.[15] APS's 2012 IRP noted 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 inherent price volatility risks associated with a natural gas-dominated energy mix."[16]

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14 Source for Figure 3: Chicago Mercantile Exchange data.

15 Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

16 2012 IRP, at p. 64.

Hedging is a commonly accepted practice in utility operations and regulation; however, it is not costless. Historically APS has incurred additional costs to hedge the volatility of its natural gas costs. These costs have averaged about $50 million per year, or just over $1.00 per MMBtu based on the utility's current volume of gas purchases,[17] and are a real, long-term cost of APS's gas procurement strategy. We have added these hedging costs to the costs of the avoided gas burns shown in Table 27 of the 2014 IRP that result from renewable generation on the APS system. This benefit from reduced fuel hedging costs is 0.9 cents per kWh of DG generation.

c. Market price mitigation

The increasing penetration of new renewable generation in Arizona and the West will place downward pressure on the region's energy market prices. New renewable generation, including solar DG, will increase the electricity supplies available in western markets. Because this generation is must-take (and has zero variable costs), it will displace the most expensive power that utilities such as APS would otherwise have generated or purchased, which typically is natural gas-fired generation. Thus, the addition of this local generation in APS's service territory will reduce the demand which APS places on the regional markets for both electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the price in these markets, which benefits APS when it does buy power or natural gas in these markets. APS is a significant buyer in the gas market, and appears to face an increasingly short position in wholesale power markets as well, given its expiring wholesale contracts over the next several years.[18] This "market price mitigation" benefit of renewable generation is widely acknowledged, and has become highly visible in markets that now have high penetrations of wind and solar resources.[19] The magnitude of this benefit will depend on the overall amount of renewables on the western grid.

From 2010-2014, the National Renewable Energy Laboratory (NREL) and GE Consulting have released the multi-phase Western Wind and Solar Integration Study (WWSIS), a major modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[20] This work focused on the West Connect area (basically, Arizona, Colorado, New Mexico, Nevada, and Wyoming), but also modeled the entire WECC grid in the U.S. This modeling included analysis of the impact of increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in the figure below.[21] Generally, the high penetration solar cases (15% to 25% penetration) result in 10% to 20% reductions in spot market prices. Note that the largest reductions in market prices occur from the initial 5% penetration of solar, which is where Arizona and the West are today.

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[17] Historical hedging costs are from APS's response to Vote Solar Data Request 2.2 in conjunction with the 2013 technical conferences on DG and NEM issues.

[18] 2014 IRP, at p. 77 and Attachment F.1(a)(4).

[19] The market price mitigation benefit is not the same as the fuel hedging benefit discussed above. Both benefits involve energy market prices for electricity and natural gas. However, the fuel hedging benefit for consumers results from a reduction in the volatility of these market prices – in other words, in a reduced risk of periodic price spikes in these commodity markets, whereas the market price mitigation benefit is from an overall reduction in the levels of these market prices. Thus, these benefits are related but do not overlap and are not duplicative.

[20] All reports from the WWSIS, are available on the NREL website at http://www.nrel.gov/electricity/transmission/western_wind.html.

[21] The high penetration solar results from the WWSIS are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), with the impact on spot market prices in Arizona reported at p. 8 and Figure 19.

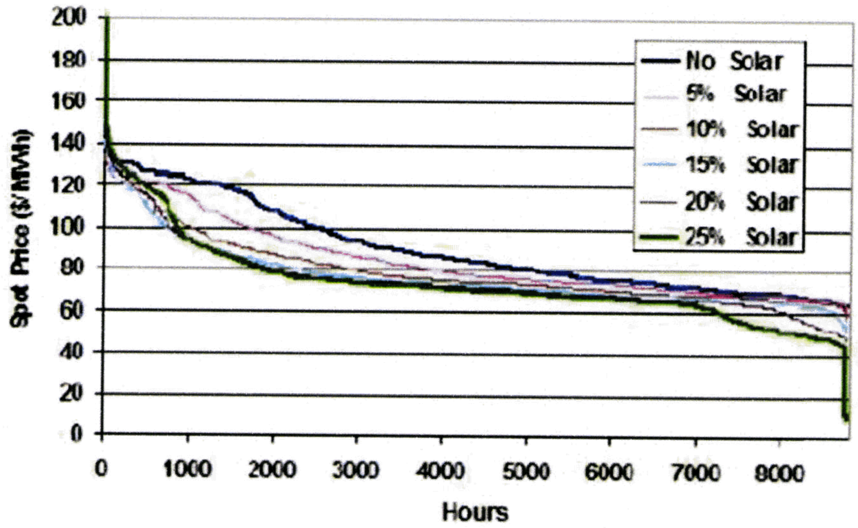

Figure 19 – Arizona Spot Price Duration Curves.

The same market mitigation benefits exist on the natural gas side. Renewable generation reduces marginal gas-fired generation, thus lowering the demand for natural gas. A study by Lawrence Berkeley National Lab (LBNL) has estimated that the gas-related market mitigation benefits of renewable energy range from $7.50 to $20 per MWh of renewable output.[22] We have used an estimate at the low end of this range -- $10 per MWh – as the estimate for the long-term market price mitigation benefits from solar DG, on both gas and electric market prices. This represents about 20% of avoided energy costs (excluding avoided carbon) and is similar to the market price mitigation benefit that has been calculated in other U.S. energy markets.[23]

c. Generation Capacity

The 2014 IRP finds that APS does not need new large-scale, fossil resources until 2018.[24] However, the 2014 IRP shows continued growth in energy efficiency and demand response programs and in distributed solar resources between 2014 and 2018 (see Attachment F.1(a)(4)), such that the new customer-sited resources developed from 2014-2018 will contribute 862 MW to meeting APS's peak demands in 2018. Solar DG, along with energy efficiency and demand response, thus contribute to deferring any new power plants until 2018. As a result, solar DG installed before 2018 has greater value than just avoiding short-term energy costs. DG also hedges against events that could accelerate the 2018 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 occurred recently at the San Onofre plant in southern California).

Combustion turbines are the least-cost source of new utility-scale capacity. CTs are the

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22 See 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" (LBNL, January 2005), at p. ix, available at http://eetd.lbl.gov/EA/EMP.

23 The market price mitigation benefit is also known as the "demand reduction induced price effect" (DRIPE), and has been quantified in several regions of the U.S. For example, in the New England ISO market, DRIPE is included as a standard component of the avoided costs of demand-side programs and has been estimated at as much as 35-36% of summer peak energy prices. See Synapse Energy Economics, "Avoided Energy Supply Costs in New England: 2013 Report" (July 12, 2013), at page 1-6, Exhibit 1-2. Available at http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-07.AESC_.AESC-2013.13-029-Report.pdf.

24 2014 IRP, at p. xvi.

long-term peaking resource typically displaced by solar DG, and are the resource that APS expects to add in 2018.[25] Based on the capital and fixed O&M cost for the type of smaller, 100 MW CTs that APS plans to add at the Ocotillo site by 2018,[26] we calculate that APS's levelized avoided generation capacity costs are $212 per kW-year in 2016 dollars, as shown in **Table 4**.

The CT fixed costs are multiplied by the capacity value of distributed PV, as a percentage of its nameplate capacity. The 2014 IRP reports the capacity value of residential PV to be 45% of nameplate capacity.[27] We have done our own calculation of the capacity value of distributed PV, based on solar output in those high-demand hours with loads within one standard deviation of the annual peak hour, using the hourly IRP load forecasts for 2016-2017 that APS provided in discovery. These high-demand hours are weighted by the amount by which the load in each hour exceeds the threshold of one standard deviation below the peak. The use of such a set of "peak capacity allocation factors" is a standard method for determining the contribution of a load or resource to the system peak.[28] As shown in Table 4, the capacity value of south-facing solar PV in 2016-2017 is 36% of nameplate, but this increases significantly, to 53% of nameplate, for west-facing systems that produce more energy in the high load hours of late summer afternoons.

Table 4: *Avoided Generation Capacity Costs ($ per kW-year in 2016$)*

Component	Value	*Notes / Sources*
CT Capital Cost	1,493	*$ per kW. 2014 IRP, Attachment D.3, for 100 MW brownfield CTs. Escalated to 2016$ at 2% per year inflation.*
x 11.17% carrying charge	166.8	*$ per kW-yr. SAIC Study, Table 3-2*
+ Fixed O&M	17.9	*$ per kW-yr. 2014 IRP, Attachment D.3*
= Total	184.7	*$ per kW-yr. 20-year levelized value*
+ Capacity reserve	15%	*APS reserve margin*
= Total with reserves	212.4	*$ per kW-yr*
x PV Capacity Value	36.2%	*South-facing, Phoenix*
x PV Capacity Value	53.2%	*West-facing, Phoenix*
+ Capacity losses	11.7%	*SAIC Study, at*
÷ PV Output[29]	1,730	*kWh/kW. South-facing, Phoenix*
÷ PV Output	1,490	*kWh/kW. West-facing, Phoenix*
Avoided Costs		
Fixed array – South-facing	5.0 cents/kWh	
Fixed array – West-facing	8.9 cents/kWh	

25 The Beck and SAIC Studies also used the fixed costs of a new CT to calculate solar DG's generation capacity value.

26 2014 IRP, at p. xiv.

27 *Ibid.*, at Attachment D.3.

28 For example, a similar PCAF approach has been used in the California Public Tool model referenced in Footnote 2 above, to determine the marginal transmission and distribution costs avoided by net-metered solar DG. Our approach values solar DG using its capacity factor in a select set of high-value hours. Thus, our method is a version of the "Capacity Factor" methods for determining the capacity value of solar. A 2012 study from NREL found that such methods can accurately approximate the results of more complex, but also more opaque and difficult-to-replicate, methods such as effective load carrying capacity (ELCC) models that APS appears to use. See Seyed Hossein Madaeni, Ramteen Sioshansi, and Paul Denholm, "Comparison of Capacity Value Methods for Photovoltaics in the Western United States" (NREL, July 2012), available at http://www.nrel.gov/docs/fy12osti/54704.pdf.

29 Using NREL's PVWATTS calculator.

This analysis focuses on the value of solar to be developed in the near future (2016-2017). APS argues in the 2014 IRP that, as solar DG penetration increases, the capacity value of solar PV will decrease, as the increased amounts of behind-the-meter 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 the future will not occur unless substantial amounts of solar are installed over the next twelve years. Further, the conclusion that the capacity value of solar will decline over time assumes that the future will look like today, only with more solar. This may not 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, for example, by installing west-facing PV systems if properly incentivized to do so. Or if additional solar reduces the price for grid power in the early-to-mid 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.

d. Transmission

The output of solar distributed generation (DG) primarily serves on-site loads and never touches the grid, and thus clearly reduces loads on the transmission grid. Even for the minority of power that a solar DG unit exports to the grid, these exports are likely to be entirely consumed on the distribution system by the solar customer's neighbors. Thus, much like energy-efficiency and demand response resources, solar DG displaces traditional generation sources must use the utility transmission system to be delivered to customers.

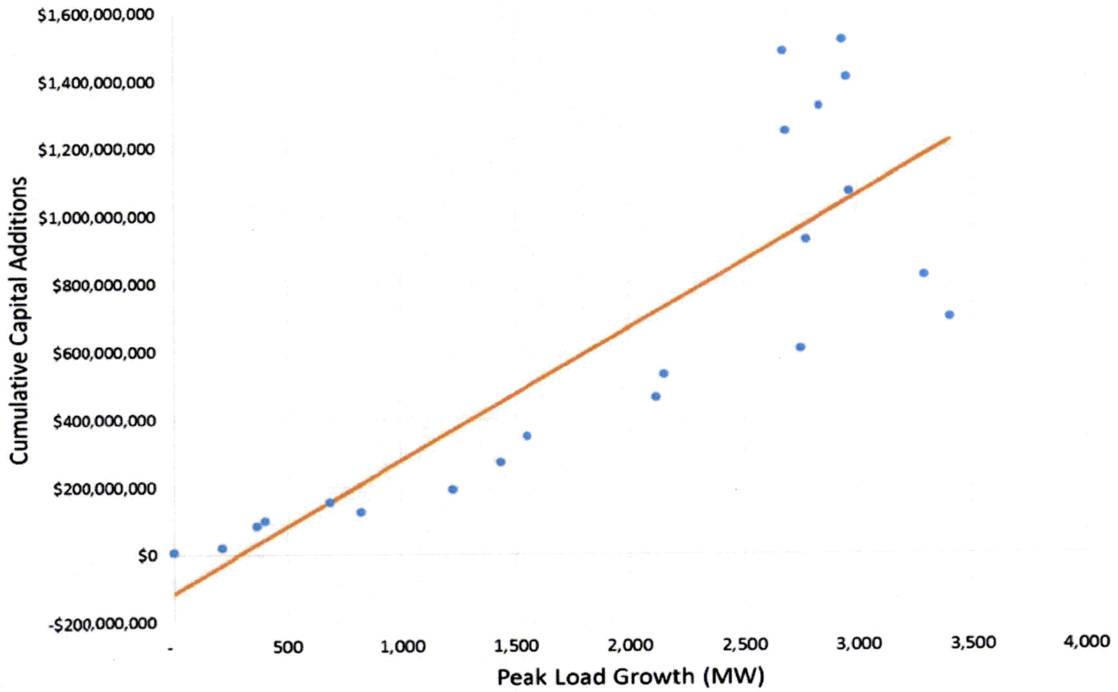
Solar DG will avoid transmission capacity costs to the extent that solar production occurs during the peak demand periods. Like energy efficiency and demand response resources, solar DG helps the utility to manage and to reduce load growth, thus avoiding and deferring the need for load-related transmission investments. This benefit is measured by the utility's marginal cost of load-related transmission capacity.

A well-accepted way to estimate long-term marginal transmission capacity costs is the industry-standard National Economic Research Associates (NERA) regression method, which is used by many utilities to determine their marginal transmission capacity costs that vary with changes in load. The NERA regression model fits incremental transmission costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of transmission associated with a change in load. The NERA methodology typically uses 10-15 years of historical expenditures on transmission and peak transmission system load, as reported in FERC Form 1, and, if available, a five-year forecast of future expenditures and load growth.

The APS 2014 IRP indicates that transmission costs for projects included in its 10-year transmission plan have been excluded from the forecast expenditures in its IRP.[30] Lacking a basis for including a five-year forecast of future expenditures and load growth, we have utilized a NERA regression based on historical peak load growth and transmission expenditures, over a 20-year period from 1995 to 2014. Crossborder's analysis of marginal transmission costs uses APS's FERC Form 1 data for this period. **Figure 4** shows the regression fit of cumulative transmission capital additions as a function of incremental demand growth on the APS system.

[30] The APS 10-year transmission plan only reports total costs over the entire period, not costs on an annual basis.

Figure 4: APS Marginal Transmission Costs



The regression slope resulting from this analysis is $392 per kW. We convert this to an annualized marginal transmission costs using a carrying charge of 11.05%. The resulting avoided cost for transmission capacity for APS is $43 per kW-year. For comparison, APS's current FERC-authorized long-term firm transmission rate is $36.13 per kW-year.[31] Although this FERC rate is an embedded, not a marginal, cost number, it does represent APS's opportunity cost to sell firm transmission capacity which is made available by reduced load growth resulting from DG and other demand-side resources.

The next step is to convert a portion of this marginal transmission capacity value to an equivalent energy price that considers the extent to which solar DG avoids investments in marginal transmission capacity. Transmission system peaks typically coincide with system demand peaks, and thus we have assumed that the contribution of solar DG to reducing transmission system peaks is the same as its contribution to avoiding the demand for generating capacity. We assume a 36% contribution to peak for south-facing systems and a 53% contribution for west-facing solar DG to estimate the contribution of solar DG to avoiding transmission costs. The result is a solar DG value for transmission capacity equal to about $14 per kW-year for south-facing systems (i.e. $37 per kW-year x 39% contribution to peak) and $19 per kW-year for west-facing. We then convert these solar DG avoided transmission capacity cost to dollars per MWh of solar DG output, assuming the same average annual outputs listed in Table 4. **Table 5** shows these calculations. The result is avoided transmission capacity costs for solar DG of $8 per MWh (0.8 cents per kWh) for south-facing systems and $13 per MWh (1.3 cents per kWh) for west-facing systems.

[31] See http://www.oasis.oati.com/AZPS/AZPSdocs/6-1-2015_Effective_Formula_Rates.pdf.

Table 5: *APS Marginal Transmission Cost*

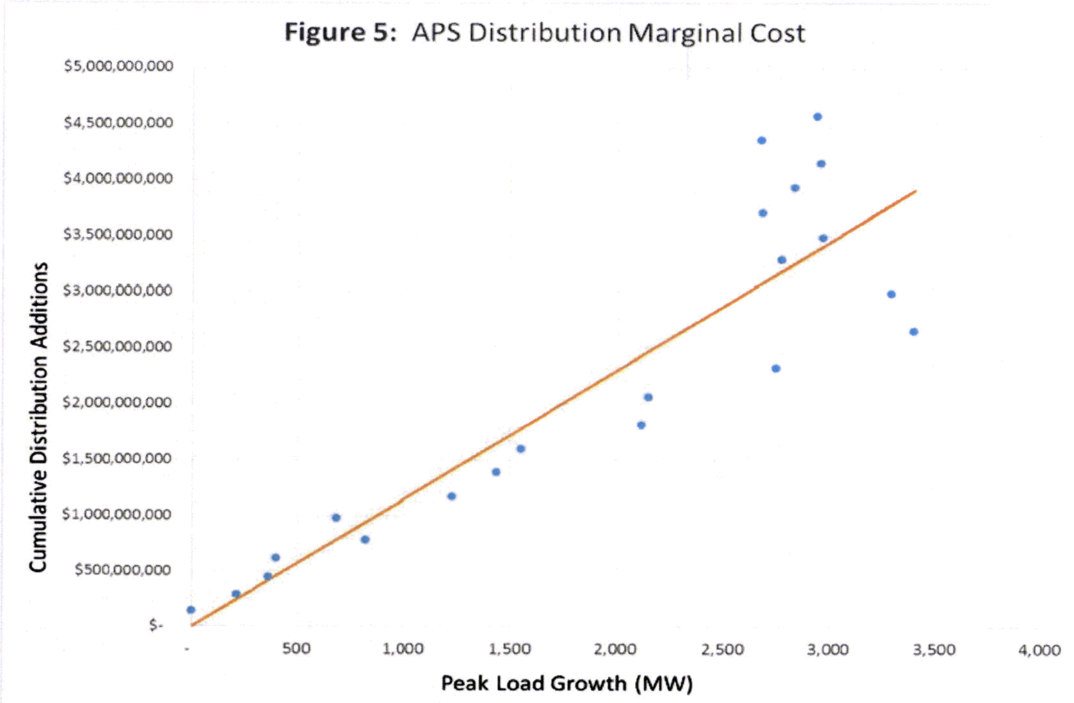
Component	Cost or Metric	*Notes*
Marginal load-related Transmission Cost	392	*$ per kW*
x Carrying Cost @ 11.05%	11.05%	*SAIC Study, Table 3-2*
= Marginal Transmission Capacity Cost	43.3	*$ per kW-year*
x Solar Capacity as % of Nameplate	36.2%	*South-facing, Phoenix*
	53.2%	*West-facing, Phoenix*
= Transmission Capacity Costs Avoided	15.7	*South, $ per kW-year*
	23.0	*West, $ per kW-year*
÷ Annual PV Output kWh per kW-AC	1,730	*South, kWh per kW-AC*
	1,420	*West, kWh per kW-AC*
= Avoided Transmission Capacity Cost	0.9	*South, cents per kWh*
	1.6	*West, cents per kWh*

e. Distribution

The extent to which solar generation avoids distribution capacity costs is a more complex question than for transmission, for various reasons. Distribution substations and circuits can peak at different times than the system as a whole, which complicates the calculation of the avoided distribution costs that result from solar DG reducing distribution system loads. It is clear, however, that the majority of solar DG output which serves the on-site load will reduce distribution loads, because that power will never flow onto the distribution system and will reduce loads served from the grid. Further, exports from solar DG to the distribution system can serve local loads, and thus unload upstream portions of the distribution system. As a result, we expect that solar DG will reduce distribution system loads, particularly at the relatively modest penetrations of DG on most distribution circuits in Arizona today, thus avoiding the cost of distribution system expansions or upgrades, and extending the life of existing equipment.

As DG penetration grows, and a deeper understanding is gained of the impacts of DG on distribution circuit loadings, we anticipate that utility distribution planners will integrate existing and expected DG capacity into their planning, enabling DG to avoid or defer distribution capacity costs. A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth even though the specific locations where these resources will be installed can be challenging to predict or to manage.

We have applied a linear regression analysis to APS's distribution capital additions and peak system load growth, analogous to the transmission marginal cost analysis presented above. The results of this analysis are shown in **Figure 4**. Converting the regression slope of $1,149 per kW to an annual cost using a carrying charge of 11.05% results in an annualized marginal distribution cost of $127 per kW-year. We note that this regression analysis considers only the historical relationship between distribution capital additions and load growth. Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid additional costs than those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction. For these reasons, this estimate of avoided distribution costs should be considered conservative.



We adopt an additional refinement in calculating the effective capacity value of solar DG at the distribution level. We calculate the solar capacity value separately for residential and commercial customers, using separate hourly load data for residential and commercial (Schedule GS) customers. This reflects the fact that a distribution circuit serving residential customers, for example, will reflect the characteristics of this type of customer. As the table below shows, the effective capacity value of solar is significantly lower on a residential circuit (20% for south-facing) than on a circuit serving commercial loads (55% for south-facing). This is because residential loads peak in the late afternoon and early evening, while commercial loads peak earlier in the afternoon when solar output is higher. **Table 6** shows the resulting marginal distribution capacity costs, for residential and commercial customers and for south- and west-facing systems.

Table 6: *APS Marginal Distribution Capacity Cost*

Component	Residential	Commercial	
Marginal load-related Distribution Cost	1,149	1,149	*$ per kW*
x Carrying Cost	11.05%	11.05%	*SAIC Study, Table 3-2.*
= Marginal Distribution Capacity Cost	127.0	127.0	*$ per kW-year*
x Solar Capacity as % of Nameplate	20.1%	55.0%	*South-facing, Phoenix*
	36.0%	53.3%	*West-facing, Phoenix*
= Distribution Capacity Costs Avoided	25.6	69.8	*South, $ per kW-year*
	45.7	67.6	*West, $ per kW-year*
÷ Annual PV Output	1,728	1,728	*South, kWh per kW-AC*
	1,492	1,492	*West, kWh per kW-AC*
= Avoided Distribution Capacity Costs	1.5	4.0	*South, cents per kWh*
	3.2	4.8	*West, cents per kWh*

3. Societal Benefits of Solar DG

Renewable DG has benefits to society that do not directly impact utility rates. When renewable generation takes the place of conventional fossil fuel generation, all citizens benefit from reductions in air pollutants that harm human health and exacerbate climate change. Demand on existing water supplies is reduced, avoiding the potential need to acquire new sources of supply. Distributed generation in particular, by siting energy generation in the built environment, results in more land being available for other uses, or as natural habitat. Distributed generation makes the power system more resilient, and stimulates the local economy. Each of these benefits can be quantified, as discussed below. We use a lower, societal discount rate of 3% in calculating these benefits, rather than the 7.2% APS discount rate used for the direct benefits.

a. Carbon

The social cost of carbon (SCC) is "a measure of the seriousness of climate change."[32] It is a way of conceptualizing the value of actions to reduce greenhouse gas emissions, by estimating the potential damages if carbon emissions are not reduced. The carbon costs which we have included in the avoided energy costs discussed above are limited to market-based cap and trade permit compliance costs, which are much lower than the true cost that carbon pollution imposes on society.

The most prominent and reputable source for estimates of the social cost of carbon is the federal government's Interagency Working Group on the Social Cost of Carbon.[33] These values have been vetted by numerous government agencies, research institutes and other stakeholders. The cost values were derived by combining results from the three most prominent integrated assessment models, each run under five different reference scenarios.[34] The group gave equal weight to each model and averaged the results across each scenario to obtain a range of values, given in the table below.

Table 7: *Social Cost of Carbon*[35] *(2007 $ per metric tonne of CO2)*

	Discount Rate		
	5%	**3%**	**2.5%**
Social Cost of Carbon	11	36	56

We recommend a base case SCC using the mid value of $36 per tonne. We escalate these benefits by 5% per year, recognizing that "future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change."[36]

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[32] Anthoff, D. and Toll, R.S.J. 2013. The uncertainty about the social cost of carbon: a decomposition analysis using FUND. *Climactic Change* 117: 515-530.

[33] Interagency Working Group on Social Cost of Carbon, "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis" (Revised July 2015). Available at https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.

[34] *Id.* The three models are the Dynamic Integrated Climate-Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect (PAGE) model.

[35] *Id.*, p. 13.

[36] *Id,* pp. 13-14. 5% annual escalation in carbon costs was also used in the California Public Tool. See the CPUC Final Public Tool referenced in Footnote 2 above, at tab "Key Driver Inputs," at Cell D33. It is also midway between the two escalation rates (2.5% and 7.5% per year) used in the carbon cost scenarios in the 2014 APS IRP.

While estimating the social cost of carbon contains many inherent uncertainties, we believe these values are defensible. Despite the unknowns, federal government agencies are required to use these figures in cost-benefit analysis. The mid-range real discount rate of 3% is a typical societal discount rate often used in long-term benefit/cost analyses. It is also a conservative assumption, when considering the diminished prosperity future generations will face in a world heavily impacted by climate disruption. Because "the choices we make today greatly influence the climate our children and grandchildren inherit," future benefits should not be significantly discounted relative to current costs.[37] As Pope Francis recently wrote in his encyclical calling for "all people of goodwill" to take action on climate change: "The climate is a common good, belonging to all and meant for all."[38]

We calculate the societal benefits of reducing carbon emissions as the SCC less the "market" carbon costs used in the direct benefits, discussed above. In addition, we also include in the total CO_2 emissions for APS the additional methane emissions that will occur from leakage in the natural gas infrastructure that serves APS's gas-fired power plants. We attach to this report as **Attachment 1** a recent white paper calculating the additional GHG emissions associated with methane leaked in providing the fuel to gas-fired power plants. This issue has received significant attention recently as a result of the major methane leak from the Aliso Canyon gas storage field in southern California. The bottom line is that the CO_2 emission factors of gas-fired power plants should be increased by 50% to account for these directly-related methane emissions from the gas infrastructure that serves gas-fired electric generation.

b. Health Benefits of Reducing Criteria Air Pollutants

Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM) causes asthma and other respiratory illnesses, cancer, and premature death.[39] Nitrous oxides (NO_X) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[40]

We recommend using the health co-benefits from reductions in criteria pollutants that were developed by the EPA in conjunction with the Clean Power Plan. These benefit estimates are recent, as they were developed in 2014 as part of the technical analysis for the proposed rule.

Particulates (PM-2.5). PM-2.5 are the particulate emissions with the most adverse impacts on health. To calculate the avoided PM-2.5 emissions from renewable DG on the APS system, we assume an emissions factor of 0.0077 lbs/MMBtu for PM-2.5 emissions from the combustion of natural gas. This factor is from "AP 42," the EPA's compilation of air pollutant emissions factors.[41] This reference states that the "PM emission factors presented here may be

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37 California Climate Change Center, Our Changing Climate: Assessing the Risks to California (2006) at p. 2. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.pdf.

38 Encyclical Letter *Laudato Si'* of the Holy Father Francis on Care for Our Common Home. June 18, 2015.

39 EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014), p. 4-17 ("CPP Technical Analysis"). Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

40 *Ibid.*

41 U.S. EPA, "Emissions Factors & AP 42, *Compilation of Air Pollutant Emission Factors*," http://www.epa.gov/ttn/chief/ap42/index.html.

used to estimate PM10, PM2.5 or PM1 emissions."[42] We use the PM-2.5 emissions factor and damage costs, because PM-2.5 are the small particulates with the most adverse impacts on health.

The EPA health co-benefit figures distinguish between types of PM, and calculate two separate benefit-per-ton estimates for PM: for PM emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter.[43] The EPA estimates that approximately 80% of primary PM-2.5 emitted in Arizona is crustal material, with the bulk of the remainder being elemental or organic carbon.[44] The emissions factor of 0.0077 lbs/MMBtu for total primary PM-2.5 does not differentiate among particle types.[45] As a result, we weigh the mid-point of each of the two benefit-per-ton estimates according to EPA's assumptions for Arizona emissions. The health benefits of reducing PM-2.5 emissions are $115 per short ton.

For elemental and organic carbon:

$$\frac{425{,}000\ (2011\$)}{1\ short\ ton} \times \frac{1.06\ (2015\$)}{1\ (2011\$)} \times \frac{1\ short\ ton}{2{,}000\ lbs} = \$225.25\ per\ lb\ PM\ (EC + OC)$$

For crustal particulate matter:

$$\frac{165{,}000\ (2011\$)}{1\ short\ ton} \times \frac{1.06\ (2015\$)}{1\ (2011\$)} \times \frac{1\ short\ ton}{2{,}000\ lbs} = \$87.45\ per\ lb\ PM\ (crustal)$$

Total:

$$(\$225.25\ \times 0.2) + (\$87.45\ \times\ 0.8) = \$115.01\ per\ lb\ PM$$

Nitrous oxides (NO_x). Heath damages from exposure to nitrous oxides come from the compound's role in creating secondary pollutants: nitrous oxides react with volatile organic compounds to form ozone, and are also precursors to the formation of particulate matter.[46] The EPA calculates health benefits of avoiding formation of either of these pollutants: $7,400 to $31,000 for ozone formation, and $17,000 to $34,000 for PM-2.5 formation, both in 2011$. We include both types of avoided health costs in our calculations, and use the mid-points of EPA's ranges of health benefits -- $24 per ton.

$$\frac{44{,}700\ (2011\$)}{1\ short\ ton} \times \frac{1.06\ (2015\$)}{1\ (2011\$)} \times \frac{1\ short\ ton}{2{,}000\ lbs} = \$23.69\ per\ lb$$

c. Water

Thermal generation consumes water, principally for cooling. Reducing water use in the electric sector through the use of renewable generation lowers the vulnerability of the electricity supply to the availability of water, and reduces the possibility that new water supplies will have to be developed to meet growing demand.

42 U.S. EPA, AP 42 Volume I, Fifth Edition, Section 1.4 (*Natural Gas Combustion*), Table 1.4-2. Available at http://www.epa.gov/ttn/chief/ap42/ch01/index.html ("AP 42").

43 CPP Technical Analysis, p. 4-17.

44 *Ibid.*, p. 4A-8, Figure 4A-5.

45 AP 42, Table 1.4-2, Footnote (c).

46 CPP Technical Analysis, p. 4-14.

The APS 2012 IRP cited a water cost of $1,114 per acre-foot.[47] Two recent California studies also have quantified the additional cost of retrofitting existing natural gas plants to reduce their water consumption, or of developing other water supplies to replace water consumed in power generation. A California Energy Commission (CEC) study calculated the "effective cost" of water use at a natural gas plant, or "the additional cost of using dry cooling expressed on an annualized basis divided by the annual reduction in water requirement achieved through the use of dry cooling."[48] In other words, if the water supply in the region with the power plant is or becomes constrained, what would it cost (in terms of the direct cost as well as the cost of lost generation efficiency) to convert the plant to run on dry cooling? The CEC found that the effective cost of saved water using this metric ranges from $3.40 to $6.00 per 1,000 gallons, or $1,110 to $1,955 per acre-foot with a mid-point of $1,530 per acre-foot.[49] Similarly, a recent study by the consulting firm Energy and Environmental Economics calculated the avoided cost of water in California based on the cost of the embedded energy in water and the avoided costs to develop new water supplies.[50] They find an avoided cost of water ranging from $442 (imported groundwater) to $1,093 (treated wastewater) to $2,349 (desalinated water) per acre foot. We eliminate the option of importing groundwater as infeasible, since the crisis of dwindling and over-used groundwater in the West is well-known.[51] The remaining three estimates are roughly consistent, and average to $1,660 per acre-foot, which is the value we have used to quantify the water savings from renewable DG, based on the quantity of water savings from renewable generation that APS stated in Table 27 of the 2014 IRP.

d. Local economic benefits

Distributed generation has higher costs per kW than central station renewable or gas-fired generation. However, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. Central station power plants have significantly lower soft costs, per kW installed, and often are not located in the local area where the power is consumed.

There have been a number of recent studies of the soft costs of solar DG, as the industry has focused on reducing such costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following tables present recent data, from detailed surveys of solar installers conducted by two national labs (LBNL and NREL), on the soft costs that are likely to be spent in the local area where the DG customer resides.

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47 2012 IRP, at pp. 135-136.

48 California Energy Commission, *Cost and Value of Water at Combined Cycle Power Plants.* CEC-500-2006-034 (April 2006), p. 4. Available at http://www.energy.ca.gov/2006publications/CEC-500-2006-034/CEC-500-2006-034.PDF.

49 *Ibid.* at p. 4; Wind Vision at p. 201.

50 Cutter, Eric, Ben Haley, Jim Williams and C.K. Woo, "Cost-effective Water-Energy Nexus: A California Case Study." The Electricity Journal, 27 (5), July 2014. Available at https://ethree.com/documents/E3_Energy_Water_EJ_web.pdf.

51 *See, e.g.*, Justin Gillis and Matt Richtel, "Beneath California Crops, Groundwater Crisis Grows." *The New York Times* (April 5, 2015). http://www.nytimes.com/2015/04/06/science/beneath-california-crops-groundwater-crisis-grows.html?_r=0.

Table 8: *Residential Local Soft Costs*

Local Costs	LBNL – J. Seel *et al.*[52]		NREL – B. Friedman *et al.*[53]	
	\$/watt	**%**	**\$/watt**	**%**
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting & interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

Table 9: *Commercial Local Soft Costs*

Local Costs	NREL – B. Friedman *et al.*			
	Small Commercial		**Large Commercial**	
	\$/watt	**%**	**\$/watt**	**%**
Total System Cost	4.97	100%	4.05	100%
Local Soft Costs				
Customer acquisition & marketing	0.13	3%	0.03	1%
Installation labor	0.39	8%	0.17	5%
Permitting & interconnection	0.01	0.2%	0.00	0%
Permit fees	0.07	1%	0.04	1%
Total local soft costs	**0.60**	**12%**	**0.24**	**6%**

These economic benefits occur in the year when the DG capacity is initially built. We have converted these benefits into a \$ per kWh benefit over the expected DG lifetime that has the same NPV in 2016 dollars. We also use more current DG capital costs than the system costs used in the LBNL and NREL studies. The result is a societal benefit of 4.7 cents per kWh of DG output for residential and 2.9 cents per kWh for commercial, or an average of 4.2 cents per kWh assuming 74% residential systems, 26% commercial.

Table 10: *Societal Benefits (20-yr levelized cents per kWh)*

Benefit	Value
Social cost of carbon – reduced damages	3.3
Health benefits – lower PM-2.5 and NOx emissions	1.0
Water benefits – increased water availability	0.2
Local economic benefit	4.2
Total Societal Benefits	8.7

4. Total Benefits

The following **Table 11** summarizes the direct and societal benefits of solar DG for both residential and commercial installations.

[52] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37 ,

[53] B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

Table 11: *Summary of Solar DG Benefits for APS (20-year levelized cents/kWh)*

Avoided Cost	Orientation	Residential	Commercial
Direct			
Energy	All	6.2	6.2
Fuel price hedging	All	0.9	0.9
Market price mitigation	All	1.0	1.0
Capacity	South	5.0	5.0
	West	8.9	8.9
Transmission	South	0.9	0.9
	West	1.6	1.6
Distribution	South	1.5	4.0
	West	3.2	4.8
Total Direct Benefits	South	15.5	18.0
	West	21.8	23.4
	Average	18.7	20.7
Societal			
Carbon	All	3.3	3.3
Criteria Pollutants	All	1.1	1.1
Water	All	0.2	0.2
Local economic benefit	All	4.7	2.9
Total Societal Benefits	All	9.3	7.5
Total Benefits			
Direct and Societal	South	24.8	25.5
	West	31.1	30.9
	Average	28.0	28.2

5. Costs of Solar DG for Participants

We have used a pro forma cash flow analysis to project the lifecycle cost of a solar DG system based on 2014 solar system costs in Arizona surveyed and reported by LBNL in their annual *Tracking the Sun* report. The median of these costs ($3.70 per watt DC) is similar to the $3.87 per watt reported by APS in Attachment D.3 of the 2014 IRP. We also used the assumptions summarized in **Table 12**.

Table 12: *Key Assumptions for the Residential Participant Cost of Solar*

Assumption	Value
Median Cost	$3.70 per watt DC
Range of Costs	$2.80 - $5.00 per watt DC
Federal ITC	30%
Financing Cost	5%
Participant discount rate	7.2%
Financing Term	15 years
Inverter Replacement	$700/kW in Year 15
Maintenance Cost	$26 per kW-year

The assumptions for the costs of commercial systems are similar, with the addition that commercial systems qualify for accelerated depreciation. **Table 1** shows the resulting levelized cost of solar for residential and commercial customers.

6. Costs of Solar DG for Non-participating Ratepayers

The primary costs of solar DG for non-participating ratepayers 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. For residential customers, the retail rate credits amount to 14.6 cents per kWh; for business customers, the credits are 8.8 cents per kWh. Based on the system average rates in the 2014 IRP, plus increases at inflation for the delivery component of APS's rates, the expected rate escalation from 2016-2035 is 2.8% per year. This escalation assumption plus a 7.2% discount rate produce 20-year levelized retail rate credits of 17.4 cents per kWh for residential and 11.2 cents per kWh for commercial (2016 $). Assuming the mix of residential and commercial systems installed in 2014 (76% residential and 26% commercial),[54] the average levelized rate credit is 16.2 cents per kWh.

Next, we add an estimate of solar integration costs using a 2012 study which APS commissioned which estimated integration costs of $2 per MWh in 2020 and $3 per MWh in 2030.[55] We assume that these costs scale to other years as a function of gas costs. Finally, we add 0.3 cents per kWh for the levelized cost of utility administration of the DG program, from the detailed data on such costs that was assembled last year for the California Public Tool model referenced above.

Table 13 summarizes these costs of DG for APS's non-participating ratepayers.

Table 13: *Non-participant Costs of Residential and Commercial Solar DG*

Cost categories	**Costs** *(20-year levelized cents per kWh)*		
	Residential	Commercial	Average
Distribution of systems	*74%*	*26%*	*100%*
Lost retail rate revenues	17.4	10.7	15.7
DG incentives	n/a	n/a	n/a
Integration costs	0.2	0.2	0.2
Program administration	0.3	0.3	0.3
Total Costs	**17.9**	**11.2**	**16.2**

Among the significant results of this analysis is that the lost revenues under APS's existing residential TOU rates are about one cent per kWh lower than under its flat rate (Schedule E-12). Thus, encouraging greater use of TOU rates would improve the cost-effectiveness of solar DG. However, the lost revenues (or, for solar customers, the bill savings) under the APS residential TOU rates with demand charges (Schedules ECT-1R and ECT-2) are just 10 - 14 cents per kWh, which are significantly below the residential cost of solar.

54 From APS's 2014 RES Compliance Report (April 1, 2015), at p. 4.

55 See 2014 IRP, at p. 43, citing Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

7. Key Conclusions of this Benefit/Cost Analysis

This analysis of solar DG as a resource for APS has considered cost-effectiveness from multiple perspectives. Other demand-side programs typically are evaluated from these multiple perspectives, and policymakers should take a similarly broad view in assessing distributed generation.

The principal conclusions of our analysis are as follows:

1. Solar DG is a cost-effective resource for APS, as the benefits equal or exceed the costs in the Total Resource Cost and Societal Tests.

2. There is a rough balance between the costs and benefits of residential DG for both participants and non-participants, as shown by the Participant and Ratepayer Impact Measure test results.

3. Significant rate design changes for residential DG customers, such as requiring solar DG customers to take service under the ECT-2 rate with demand charges, would upset this balance.

3. The benefits of DG significantly exceed the costs in the commercial market. Encouraging growth in this market would help to ensure that DG resources as a whole provide net benefits to the APS system.

4. The benefits of solar DG in APS's service territory are higher for west-facing systems. If there is a concern about the cost of DG to non-participating ratepayers, particularly for residential customers, an important step to address such a concern would be to encourage and incentivize west-facing systems.

5. The analysis indicates lower costs of solar DG to non-participants under APS's existing residential time-of-use (TOU) rates. Lost revenues under APS's existing residential TOU rates are about one cent per kWh lower than under its flat rate (Schedule E-12). Thus, encouraging greater use of TOU rates also will improve the cost-effectiveness of solar DG.

Attachment 1

Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

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1. Summary

Natural gas has been commonly depicted as a "bridge" fuel between coal and renewable energy for the generation of electricity. Natural gas is considered more environmentally friendly because burning natural gas produces less CO_2 than coal on a per unit of energy basis. Most analyses of the greenhouse gas (GHG) emissions associated with burning natural gas to produce electricity use an emission factor of 117 lbs of CO2 per MMBtu of natural gas burned. However, this number does not include methane leaked to the atmosphere during the production, processing, and transmission of natural gas from the wellhead to the power plant. Methane is both the primary constituent of natural gas and a potent greenhouse gas (GHG), so quantifying the methane leakage is important in assessing the impact of natural gas systems on global warming.

Methane is emitted to the atmosphere from natural gas systems in both normal operating conditions and in low frequency, high emitting incidents. The Environmental Protection Agency's (EPA) "Inventory of U.S. Greenhouse Gas Emissions and Sinks" attempts to calculate methane emissions from natural gas systems using a "Bottom Up" accounting method, which essentially adds up methane emissions from production, processing, transmission, storage, and distribution. This method sets a reasonable baseline for methane emissions during normal operating conditions, but does not account for low frequency high emitting situations.

Low frequency high emitting situations happen when some part of the production, processing, or transmission systems fail, leaking large amounts of methane into the atmosphere. The recent Aliso Canyon leak from a major Southern California Gas storage field in Parker Ranch, California is probably the best-known example of a low frequency high emitting event. The Aliso Canyon leak has emitted 2.4 MMT CO2 Eq., or roughly 1.5% of total yearly methane emissions from all U.S. natural gas Infrastructure, in a single event. Several studies have shown that low frequency high emitting events like Aliso Canyon contribute significantly to methane emissions from natural gas systems.

The following analysis and discussion lays out an argument for increasing the CO2 emission factor for burning natural gas in power plants to include the CO2 equivalent of the methane emitted in the production, processing, transmission, and storage of natural gas, leaving out the losses in local distribution that are downstream from power plants on the gas system. A conservative starting point for the leakage from wellhead to power plant is that 2% of natural gas produced is lost to leakage in the form of methane. This estimate is based the IPCC Fifth Assessment Report, the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," adjusted based on several studies quantifying how the EPA's method underestimates actual emissions.

Using the conservative estimates of 2% of total production emitted, and a global warming potential (GWP) of 25 (the low end of methane's GWP) increases the CO2 emitted by burning methane to 175.5 lbs of CO2 Eq. per MMBtu of natural gas burned (a factor of 1.5). Using a GWP of 34 (high end) yields 196.6 lbs of CO2 per MMBtu of natural gas burned (a factor of 1.68).

2. Measuring Natural Gas Leakage (Methods)

Determining methane leaks from natural gas systems is relatively new field of study. Until 2011 methane leaks were calculated almost exclusively using a Bottom Up accounting method based on data published in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks". Several issues with this method, including outdated Emission Factors and low frequency high emitting events, have led researchers to use "Top Down" aerial measurements of methane leakage.

Bottom Up. Bottom Up (BU) methods attempt to identify all sources of methane emissions in a typical production chain and assign an Emission Factor (EF) to each source. The total emissions are determined by adding up all of the EFs through the life cycle of natural gas. BU measurements are useful because they avoid measuring methane from biogenic sources (landfills, swamps, etc), anthropogenic sources in geographic proximity to natural gas systems (coal plants, oil wells, etc), and only require an engineering inventory of equipment and activity. However, BU measurements often rely on decades-old EFs. The EFs used in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" are based on a report published in 1996, which in turn is based on data collected in 1992. The EPA has developed a series of correction factors based on technological improvements and new regulations.

BU studies have been shown to underestimate methane emissions from natural gas systems.[1]–[5] While outdated EFs can cause both under and overestimation of emissions, low frequency high emission events are responsible for consistent underestimation of emissions by BU calculations.[1], [5]–[7] A recent study in the Barnett Shale region of Texas found that 2% of facilities were responsible for 50% of the emissions and 10% were responsible for 90% of the emissions.[5] BU measurements do not accurately take into account these low frequency high emitters. First, most BU measurements either sample only a few facilities or rely on facility and equipment inventories rather than local measurements. Secondly, most BU data is self-reported. Finally, several studies have found that the low frequency high emitters were both spatially and temporally dynamic, with the high emission rates resulting from equipment breakdowns and failures, and not from design flaws in a few facilities.

Top Down. Top Down (TD) methane measurements have used aerial flyovers to measure the atmospheric methane content, then use mass balance and atmospheric transport models to determine methane emissions from a geographical region. A signature compound such as ethane is used to distinguish fossil methane from biogenic methane. Unlike BU measurements, TD measurements account for low frequency high emitter situations. TD studies consistently measure higher levels of methane emissions than do BU studies. Only recently have measurements TB and BU studies converged, and this convergence was only after additional low frequency high emission situations were characterized in BU studies.[5]

3. Methane Leak Calculations

The EPA divides methane emissions from natural gas systems into four categories: Field Production, Processing, Transmission and Storage, and Distribution. This analysis focuses on only the first three categories, leaving out local distribution networks. Detailed descriptions of these categories can be found in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."

US Natural Gas Production 2005 - 2013

Expressed as BCF Natural Gas

Source	2005	2009	2010	2011	2012	2013
Withdrawals from Gas Wells	16,247	14,414	13,247	12,291	12,504	10,760
from Shale Shale Wells	0	3,958	5,817	8,501	10,533	11,933
Total Withdrawals from Natural Gas Systems	16,247	18,373	19,065	20,792	23,037	22,692

Emissions from US Natural Gas Systems 2005 - 2013

Expressed as % of Total Production

Stage	2005	2009	2010	2011	2012	2013
Field Production	0.91	0.66	0.58	0.48	0.42	0.41
Processing	0.20	0.20	0.18	0.20	0.19	0.20
Transmission and Storage	0.59	0.56	0.53	0.51	0.44	0.47
Total	1.70	1.43	1.30	1.19	1.05	1.07

Using the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant (excluding local distribution) are currently estimated to be 1.1% of production.[8] Given that EPA uses a BU method for calculating emissions, it is reasonable to assume that 1.1% is an underestimation. A 2015 study that combined seven different datasets from both TD and BU and included the most aerial measurements to date concluded that methane emission were 1.9 (1.5 – 2.4) times the number reported the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."[5] If the EPA's estimate is multiplied by 1.9 the result is 2.09%.

The IPCC Fifth Annual Report agrees, stating that: "Central emission estimates of recent analyses are 2% - 3% (+/– 1%) of the gas produced, where the emissions from conventional and unconventional gas are comparable." [9]

4. Global Warming Potential of Natural Gas

Global warming potentials (GWP) provide a method of comparing different GHGs. A GWP is: "a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide." The Intergovernmental Panel on Climate Change (IPCC) regularly publishes updated GWPs based on the most current scientific knowledge. The most current value for methane (based on the 2013 IPCC AR5) is 34.[9] The previous value (based on the 2007 IPCC AR4) is 25. Policy makers continue to tend to use the values closer to 25.[9] For example, the EPA uses 25 in its "Inventory of U.S. Greenhouse Gas Emissions and Sinks," but 34 is more commonly used in the scientific literature.[10]

5. Conclusion

This report recommends the use of a 2% emissions rate for methane leakage from natural gas systems when calculating the GHG emissions associated with natural gas-fired electric generation. Current analyses use 117 lbs of CO2 per MMBtu as the emissions factor from burning natural gas, which essentially assumes zero leakage. Adopting a 2% emission rate would increase this number to 175.5 lbs of CO2 per MMBtu of natural gas burned, assuming a conservative GWP of 25.

6. Citations

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[2] R. A. Alvarez, S. W. Pacala, J. J. Winebrake, W. L. Chameides, and S. P. Hamburg, "Greater focus needed on methane leakage from natural gas infrastructure.," *Proc. Natl. Acad. Sci. U. S. A.*, vol. 109, no. 17, pp. 6435–40, 2012.

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