A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering

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Solar America Board for Codes and Standards

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Executive Summary

Net energy metering (NEM) is a state-level policy that permits a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. Forty-three states, the District of Columbia, and Puerto Rico have instituted NEM in some form to permit self-generation, typically at the urging of customers seeking to use solar, wind, and other renewable energy facilities. These NEM policies vary from state to state, particularly regarding how large an individual installation can be and how much NEM will be allowed in the aggregate. Restrictions on NEM are almost always driven by utility concerns that lower utility bills for NEM customers will lead to higher utility bills for customers who do not have NEM.

The intent of this report is to provide a consistent methodology to analyze the potential rate impacts of NEM. With reliable estimates of rate impacts, regulators can make informed decisions regarding modification of NEM rules, and our intent here is to provide a methodology for more reliable estimates. In this report, we review and synthesize three studies performed for major utilities in Arizona, California, and Texas during the past decade. All three were on a scale far beyond the scope of this report, but the broad categories of costs and benefits identified in the studies are not specific to a given utility.

Based on this review, we provide a generalized approach for any state or utility to analyze the potential rate impact of NEM in its area. The analysis and results of such studies are utility-specific, but the methodology should not be. If benefits exceed costs, then regulators may want to consider lifting restrictions on NEM and crediting NEM customers for the net benefits they provide. If costs exceed benefits, then other ratepayers are subsidizing NEM customers, and regulators must decide whether externalities such as reduced pollution, job creation, and resource diversity justify the subsidy.

Costs of NEM are often argued to be the utility's lost revenue and any associated administrative costs. Every kilowatt-hour (kWh) generated by an NEM customer means one less kWh sold by the utility at retail rates. The retail rate in question depends on the type of customer. Most residential and small commercial customers have a bundled rate that covers both their utility's fixed and variable costs, while large commercial customers typically have an "energy" charge based on kWh for variable costs and a "demand" charge based on the customer's peak usage, measured in kW, for fixed costs.

Typically, an NEM solar facility has minimal impact on the demand component of the demand-metered customer's bill. Even if the customer would have experienced peak demand coincident with sunshine without a solar array, and a solar array significantly lowered demand at that time, demand near that peak level after sunset or when the system is not operating will be unchanged. Thus, typically, demand-metered customers with an NEM solar facility primarily offset energy charges, which are much lower than the bundled rates for residential and small commercial customers. As the energy charge is based on variable costs that the utility no longer has to incur, the impact of NEM for these customers should be negligible. At present, roughly two-thirds of the installed capacity of all NEM solar facilities is located on commercial customer property, with much of that sized over 100 kW and likely to be offsetting the energy charges of demand-metered customers.

The other aspect of NEM costs is the utility's administrative expense. Most utilities use proprietary billing software that is costly to adapt for NEM. Therefore, in the short term many utilities use hand billing for NEM customers to avoid incurring a large cost for a relatively small group of customers. However, over the medium to long term, changes to a utility's billing software to support evolving energy use patterns—dynamic rates, advanced metering, plug-in electric vehicles, etc.—will occur in the ordinary course of business. Logically, updating billing software to handle NEM program participants can occur as part of this longer-term evolution. Accordingly, we believe that the anticipated long-term administrative costs of a NEM program should be used in any rate impact analysis, on the reasonable presumption that billing of NEM customers will be automated.

On the benefits side of the rate impact calculation, the three studies we reviewed indicate that NEM allows utilities to save fuel expenses, avoid line losses, and realize at least some capacity benefit, while also suggesting various secondary benefits. An important component to the benefit calculation is determining what generation will be offset. Utility variable rates are based on average operating costs, and more than two-thirds of utility generation is from high capital cost/low operating cost coal, nuclear, and hydropower facilities. NEM solar facilities generally do not offset these baseload generators. Rather, they offset the lower capital cost/higher operating cost natural gas-fired facilities that operate during business hours and other periods of above-average demand to supplement baseload generation.

No matter which type of generation is offset, line loss savings are an important benefit of NEM. For every kWh generated by a utility-scale generator, five to ten percent of the electricity will be lost on the way to customers in the form of transmission and distribution losses. In contrast, NEM generation occurs at the customer's site, with almost no line loss. Neighbors typically use excess generation from a NEM facility, with negligible line losses. The demand on the distribution circuit serving the NEM customer drops by the full amount of the facility's generation at any given moment. Any line losses are utility- and time-specific, but for many utilities, higher losses occur during hot, sunny conditions. To calculate line loss savings associated with NEM solar facilities requires a reasonable estimate of average daytime line losses for that utility.

The most contentious element of the benefits calculation relates to capacity benefits. To the extent that NEM facilities allow a utility to delay or avoid construction of the next generator, transmission line, substation, or distribution line, there are clearly associated savings enjoyed by the utility and its customers. The studies we reviewed differed in their treatment of capacity benefits. We conclude that capacity benefits are real and incremental, with aggregate distributed solar generation far more stable and predictable than the obviously intermittent nature of individual solar facilities. We also include information about the potential for combining solar energy with demand response or energy storage programs to assure capacity benefits. While solar energy facilities are typically available during high demand periods, utility planners are hesitant to attribute capacity values to them because of the perception that they are not as reliable as traditional resources. Firming the output of solar energy generation with demand response or energy storage will allow utility planners to confidently rely on solar energy, particularly as new smart grid capabilities come online that allow grid operators to balance supply and demand at local levels in real time.

Author Biographies

Jason B. Keyes focuses on regulatory matters related to interconnection of distributed generation to the U.S. electric grid. On behalf of the Interstate Renewable Energy Council, he has participated in interconnection and net metering rulemakings at the utility commissions of fifteen states. As a partner at Keyes & Fox, LLP, he also represents private clients with all regulatory aspects of renewable energy project development. Prior to his legal career, Mr. Keyes managed government contracts and business development for eight years at JX Crystals Inc., a pioneer in the field of high-concentration solar energy systems. In the early 1990s, he helped develop the integrated resource plan and the demand forecast at Washington State's largest utility. Mr. Keyes received his juris doctor from the Seattle University School of Law, a master of arts in economics from the University of Washington, and a bachelor of arts from Dartmouth College. Mr. Keyes is a member of the Washington State Bar Association.

Joseph F. Wiedman represents clients before regulatory commissions nationwide with a particular focus on expanding renewable energy markets through establishment of state programs and policies that facilitate the growth of renewable energy. On behalf of the Interstate Renewable Energy Council, he has participated in rulemakings related to interconnection, net metering, and development of community renewables programs nationwide. As a partner at Keyes & Fox, LLP, Mr. Wiedman has worked on a broad range of matters related to the development and implementation of renewable energy programs. Over the course of his career, he has worked in academia, government, and private business related to regulation of the energy and telecommunications industries in various capacities. Mr. Wiedman holds a juris doctor from the University of California, Berkeley. He also holds a master of arts from Illinois State University in applied economics with an emphasis in the economics of electricity, natural gas, and telecommunications, and a dual bachelor of arts from the University of Illinois-Urbana in economics and Russian and Eastern European Studies. Mr. Wiedman is a member of the State Bar of California.

Solar America Board for Codes and Standards

The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds the Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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Table of Contents

INTRODUCTION

Net energy metering (NEM) is critical to supporting customer investment in renewable distributed generation (DG). Although there are various policy options related to NEM, the basic structure allows a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. To facilitate the expansion of opportunities for customers to invest in DG, 43 states, the District of Columbia, and Puerto Rico have implemented NEM programs. Increasing interest in NEM programs has come at a particularly important juncture in the development of the solar industry as module prices declined markedly in 2009-2010. This decline in prices resulted in increased consumer interest in solar energy despite the economic climate. However, while many NEM programs in this two-year period broadened in scope, the quality of programs continued to vary widely between the states.

NEM programs have met with resistance, notably from utilities concerned that a robust NEM program in their service territory would result in significant rate impacts for nonparticipating customers and—in the case of an investor owned utility (IOU)—a loss of profit. Unfortunately, a detailed analysis of potential NEM rate impacts has only recently begun, so potential rate impacts are not well understood and there continues to be disagreement about the appropriate inputs for such analysis.

Despite this disagreement, efforts have moved forward, particularly in Arizona, California, and Texas, to more rigorously quantify the rate impacts of NEM programs. Together, these efforts facilitate the development of a consensus view of the most important considerations in the valuation of renewable energy resources, particularly distributed solar energy systems.

To assist state policy makers, utilities, utility regulators, renewables advocates, and other stakeholders in their efforts to evaluate the potential rate impacts of NEM in their states, we suggest a methodology based on standard NEM provisions in states with the highest levels of program participation. Because solar facilities make up the majority of net-metered facilities participating in state NEM programs, we focus on the impact of net-metered solar facilities. We analyze the methodology for determining rate impacts, and do not undertake a review of any particular state renewable energy program. In addition, we consider only the impact of net-metered solar facilities on non-participating customers' rates, not economic impacts, environmental impacts, or impacts on participating customers investing in DG resources.

The "Present Status of Net Energy Metering" section provides a background discussion focusing on the key NEM program variables that can impact rates. The "Relevant Studies for Evaluating Net Energy Metering Rate Impacts" section discusses the costs and benefits of NEM that should be considered in a rate impact analysis. The "Best Practices in Valuing Net Energy Metering" section reviews California's efforts to assess the rate impacts of NEM, which constitute the most thorough analysis to date. Finally, we present conclusions and recommendations. We cite references within the text by title or author, and include full citations in the "References" section at the end of the report.

PRESENT STATUS OF NET ENERGY METERING

NEM as a policy choice for supporting customer investment in renewable energy resources is thriving. According to the Database for State Incentives for Renewables & Efficiency *(http://www.dsireusa.org)*, 43 states, the District of Columbia, and Puerto Rico have adopted an NEM policy, as shown in Figure 1. Many states have adopted a policy that applies only to IOUs. However, some statewide policies also apply to municipal and cooperative utilities. Program rules vary widely among states on such crucial issues as overall NEM program size, facility size, allowance of third party ownership, and the ability to roll over excess generation from one month to the next.

Details on state NEM policies are thoroughly documented in an annual publication by the Network for New Energy Choices (NNEC) entitled Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures (Network for New Energy Choices, 2011). The document provides side-by-side comparison of state policies in 11 areas related to facility size, program size, eligibility, metering, treatment of excess generation, allowance of third party ownership, and protection from standby charges and other fees that nonparticipating customers do not face. Within those policy areas, NNEC awards a sliding scale of points based on the policy choices each state has made with the most points going to states with policies that accommodate more distributed generation.

For purposes of reviewing rate impacts of NEM programs, system size limitations, program size limitations, rollover of excess generation, and standby charges are discussed here. Policy choices in these areas directly affect rate impacts. These restrictions are often undertaken in an effort to address concerns about rate impacts on non-participating customers, with the intent of mitigating the perceived rate impacts of a NEM program. And yet, expansive NEM policies are an important element in state efforts to promote customer-sited renewable generation. (Itron, 2010; Doris, McLaren, Healey, & Hockett, 2009; Paidipati, Frantzis, Sawyer, & Kurrasch, 2008)

System Size Limitations

Figure 1 shows that eligible system size ranges from 20 kilowatts (kW) in Wisconsin—the size of a very large residential system—to two megawatts (MW) or more in 14 states.

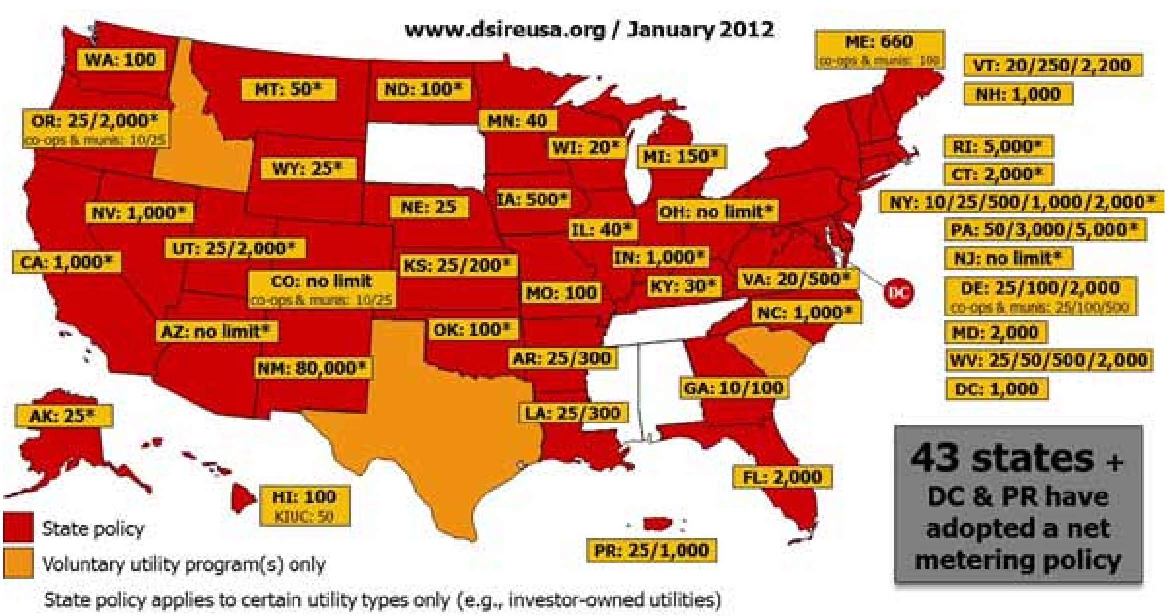

Figure 1. State net energy metering (January 2012, http://www.dsireusa.org). Numbers indicate residential/ commercial individual system capacity limits.

As Table 1 shows, the top ten states for customer-sited solar energy share the attribute of allowing NEM facilities of at least one MW, with the exception of Hawaii, which has unique characteristics.

TABLE 1
Top 10 States by Installed Capacity and Their NEM System Size Cap

2010 Rank by State	2010 Market Share	Cumulative MWDC	NEM System Size Cap
1. California	48%	1,022	1,000 kW
2. New Jersey	12%	260	no limit
3. Colorado	5%	117	no limit
4. Arizona	5%	105	no limit
5. Nevada	5%	102	1,000 kW
6. Florida	3%	73	2,000 kW
7. New York	3%	56	2,000 kW
8.Pennsylvania	3%	55	5,000 kW
9. Hawaii	2%	45	100 kW
10. New Mexico	2%	43	80,000 kW
All Other States	12%	261	

Source: Sherwood, L., ***U.S. Solar Market Trends 2010****, Interstate Renewable Energy Council, June 2011. (Total of 2,139 MW_{DC})*

Program Size Limitations

Limitations on program size and the size of eligible systems often go hand in hand. These policies appeal to those who believe that NEM programs are a subsidy, but this position is widely debated. A December 2009 report by the National Renewable Energy Laboratory reviewed how states have considered the rate impacts issue, with no example of a state finding that subsidization exists (Doris, Busche, & Hockett, p. 15). The report notes that North Carolina and Maryland looked into the issue and decided not to attempt studies because the experience in other states "had not shown a negative rate impact." The report notes that in New York, an attempt at quantification was underway, but "the impacts have not been large enough to measure under the current data collection scheme." Having surveyed states on the issue, the report concludes that "[t]he states that have increased the net metering system size cap generally cited the limited impacts of net metering on ratepayers in other states."

These policy choices also hinder the development of renewable energy markets in two ways. First, program capacity caps signal to potential new energy developers that their efforts will ultimately be thwarted, not by a lack of customer interest, but by regulatory restrictions. At the same time, a cap on DG system size to less than one MW precludes development of economical systems above the size cap, and those larger systems have been an important driving force in market growth during the past few years. In the end, both policy choices signal to developers that their investments in building solar businesses are best made elsewhere.

Rollover of Excess Generation

At the heart of any NEM program is the treatment of generation in excess of a customer's needs. When implemented properly, NEM has nearly the same impact on a participating customer's utility bill as would occur if the customer-generator used a bank of batteries to store energy until the customer's demand exceeded his or her generation (batteries have modest losses, so NEM has a slightly greater utility bill impact). At its most basic, NEM allows a customer's meter to run backwards when the customer produces more power than the customer can use. (Note that most mechanical meters can actually run backwards, but for newer digital meters, "running backwards" is figurative.) States that do not allow this basic aspect of NEM simply do not "net meter" in the widely accepted understanding of the concept.

Once treatment of instantaneous excess generation is addressed, policy makers must consider the treatment of generation at the end of a particular billing period as they develop program rules. The most expansive net metering policy is to allow for indefinite rollover of net excess generation from billing period to billing period until it is used by the customer-generator. This policy choice provides the greatest flexibility in allowing customers to design a renewable energy system to meet their individualized needs, given the variations in output from a system over the course of the year and a customer's yearly consumption pattern. For many homeowners seeking to meet their entire annual load, solar energy generation in the sunny summer months exceeds their summer loads, with the excess offsetting loads in the winter.

Perpetual rollover of excess generation also avoids possible federal regulatory issues related to wholesale sales and addresses concerns that NEM might produce incentives for customers to oversize their systems. As well, the Internal Revenue Service has indicated in at least one private letter ruling that payment for excess generation is taxable income.

Stakeholders with concerns over the rate impacts of NEM often attempt to limit possible rate impacts by requiring the customer-generator to donate net excess generation at the end of a calendar year or some other twelve month period to the utility or to accept payment for the net excess generation at the utility's average avoided cost. Both of these program choices undervalue the net excess generation a customer provides to a utility by providing no value or valuing the on-site, customer-owned renewable energy generation at the cost of fossil fuel generation. NEM programs almost always have a requirement that systems be sized to meet no more than the customer's expected consumption, so substantially oversized systems are not built. Treatment of annual excess generation is an issue for the odd year when generation was higher than expected or consumption was lower than expected. Perpetual rollover of excess generation avoids the administrative burden of an annual reconciliation and gives the customer an assurance of credit for all energy delivered to the utility.

Standby Charges

There have been many instances of utilities proposing special tariffs for customer-generators structured as standby charges or other fees to compensate the utility for possible services that the utility provides. A utility's regulator—the state public utilities commission for IOUs, the city council for many municipal utilities, and other boards for various co-ops and public utility commissions—must approve such tariffs. From another angle, some utilities have argued that any requirement that standby charges or fees may not be imposed is an unwarranted subsidy by nonparticipating ratepayers. Unfortunately, this argument does not account for the fact that standby charges were generally developed as a rate option for much larger cogeneration or combined heat and power facilities that supply energy on a steady 24/7 basis. These generators lower a customer's peak demand, and therefore the customer's demand charge, while their utility stands by to meet the customer's entire load if the generator fails. Solar energy generation ceases every night and dips during daytime due to cloud cover. For most commercial customers, this means that the utility will impose a demand charge based on peak demand that is nearly what the customer would pay without a solar generation facility. While residential customers typically do not have demand charges and can reduce their utility bills to nothing with NEM depending on facility size, the utility is still in the favorable position of receiving daytime energy that is more valuable than nighttime energy, and typically at least as valuable as early evening energy.

Because of these concerns, Freeing the Grid gives state programs that institute standby charges and other fees for net-metered systems fewer or even negative points. To the extent that proposed standby charges are based on actual rate impacts for a particular utility, institution of the charges is a policy choice available to regulators, but an NEM policy should be reviewed without standby charges to determine what rate impacts exist.

Relevant Studies For Evaluating Net Energy Metering Rate Impact

As solar has become a viable option for increasing numbers of consumers, considerable federal, state, and utility attention has begun to focus on valuation of solar energy from DG resources. The following three sections offer a review of recent solar valuation studies, recent efforts in California to develop a methodology for valuing demand-side resources including solar energy systems, and recent efforts to value the capacity benefits provided by solar energy systems. Synthesis of these efforts will provide insight into areas of consensus on the valuation of solar and, therefore, form the foundation of best practices for assessing the rate impacts of NEM.

Studies Valuing the Benefits of Solar Resources

There have been several efforts to value solar energy generation in specific locales, of which three stand out as particularly comprehensive. The first two are discussed in this section: The Value of Distributed Photovoltaics to Austin Energy and the City of Austin (Hoff et al., 2006, followed by a 2008 revision) (AE study) and Distributed Renewable Energy Operating Impacts and Valuation Study (R.W. Beck, Inc., 2009) (APS study). The third comprehensive study of solar energy valuation is incorporated within a broader review of the costs and benefits of net metering for California's largest IOUs. We review that study in the "California's Cost-Benefit Methodology for Distributed Energy Resources" section.

The Austin Energy (AE) and Arizona Public Service (APS) studies discussed below provide an in-depth look at the value solar photovoltaic (PV) generation can bring to the grid for a specific utility. Moreover, each study was subject to scrutiny from many perspectives and stakeholders, and, taken together, they represent a good starting point for identifying consensus elements of the value solar PV can bring to the grid.

Austin Energy Study

To support its determination to move forward with a goal of installing 100 MW of solar generation by 2020, Austin Energy commissioned Clean Power Research to quantify the benefits of solar generation to the utility. At the onset, the authors identified two perspectives as forming the core of the AE study—the "utility" perspective and the "all ratepayer" perspective—and the study's authors used these perspectives to inform the development of a methodology for valuing the benefits of distributed PV.

Based on the various perspectives, the AE study authors presented a comprehensive list of benefits stemming from distributed PV based on research performed by the National Renewable Energy Laboratory, and including the value of energy production, generation capacity value, transmission and distribution (T&D) deferrals, reduced transformer and line losses, environmental benefits, natural gas price hedge, disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control. Ultimately, the last four potential benefits listed here were not included in the AE study for various reasons, and the benefits associated with disaster recovery were studied, but not included in the primary analysis. (Hoff et al., 2006, p. 12).

The AE study found that PV offered a present value of $1,983 to $2,938/kW or on a levelized basis between 10.9¢ and 11.8¢ per kilowatt-hour (kWh) in 2006 dollars. In a 2008 recalculation, Austin Energy found substantially higher average values of $3,139/kW and 16.4¢/kWh in 2008 dollars.

From the standpoint of NEM, when a customer receives a credit for excess generation that can be used when consumption exceeds generation, Austin Energy's residential retail rate as of December 2010 on tariff E01 (the standard residential tariff), including a fuel adjustment of 3.65¢/kWh, is approximately 7.2¢/kWh for less than 500 kWh of consumption per month, 9.67¢/kWh for consumption of more than 500 kWh/month from November through April, and 11.47¢/kWh for consumption of more than 500 kWh/month from May through October. All of these rates are well below the 16.4¢/kWh unadjusted value of the benefits PV brings to Austin Energy.

Discussion of AE Study

In reaching these figures, it is important to note that ultimately, two important benefits were not included in the final valuation—disaster recovery and reactive power control.

Disaster recovery benefits were not included because the quantification of this benefit was the first known attempt to do so by the authors and, therefore, the results did not have the level of certainty desired. Ultimately, the authors of the study recommended further study of the issue by Austin Energy in combination with battery storage especially in the context of a hybrid electric vehicle program. Disaster recovery benefits were estimated to be $2,701/kW for capacity and for energy generation to range from $1,121 to $1,578/kW. These numbers would almost double the overall value of PV generation to Austin Energy.

Voltage support and reactive power control had a value of $0/kW in the final model because current technical standards do not allow for this benefit to be provided by inverters for the benefit of utility operators. The study estimated the value of this benefit at up to $20/kW, but the figure could be much higher, and the technology to provide this benefit is available. At present, the technology may not be incorporated into inverters pursuant to IEEE Standard 1547, the existing technical standard for interconnections. A working group of electrical engineers is developing a standard for interconnection of generation with inverters that provide reactive power and voltage support, which will become IEEE Standard 1547.8.

A recent study by the Electric Power Research Institute includes the graphic in Figure 2, displaying how voltage is less variable on a typical 12 kV circuit with solar energy and voltage control than it would be with no solar energy facilities at all. Already, New Jersey utility PSE&G (Public Service Electric & Gas Company) has mounted tens of thousands of individual solar modules on its power poles and is using the available voltage and reactive power support (as a utility, it does not need to wait for completion of IEEE 1547.8). Because of these developments, in any valuation of solar energy generation, it now seems reasonable to consider the value of voltage and reactive power support.

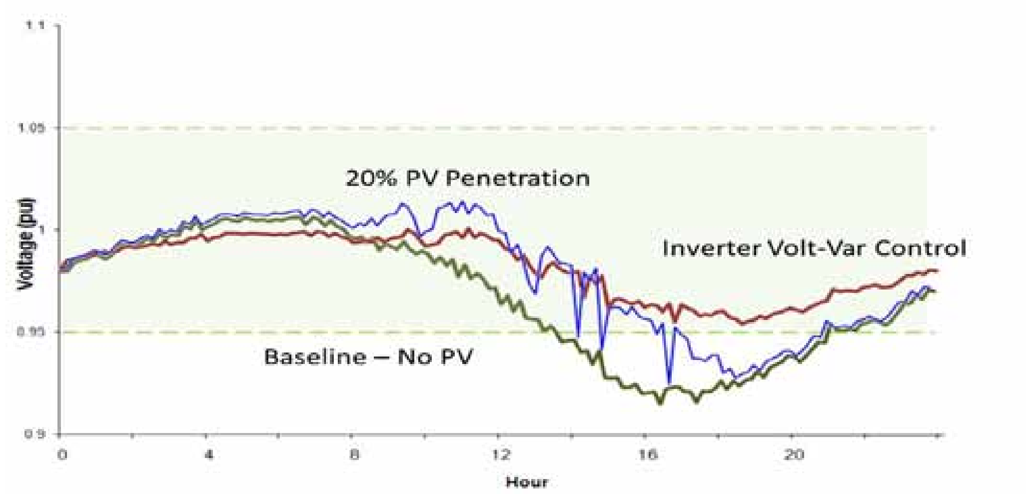

Figure 2. Percentage variation from rated voltage on a typical 12 kV line without PV (the green line, with lowest point), with 20% PV penetration without voltage and reactive power control (the jagged blue line), and with "Inverter Volt-Var Control" (the brown line, with the least voltage variability). Source: Seal, B., Monitoring, Information, and Control: Management for Tomorrow's PV (PowerPoint), May 2010 (reprinted with permission).

Arizona Public Service Study

In early 2008, Arizona Public Service (APS) commissioned R.W. Beck, Inc., Energized Solutions, LLC, Phasor Energy Company, LLC, and Summit Blue Consulting, LLC to assess the impact of wide-scale deployment of distributed PV along with solar hot water systems and commercial daylighting systems on the APS system. Among the specific objectives of the study was an assessment of the benefits wide-scale deployment of these technologies could have for the APS system. In this sense, the APS study views the potential benefits of deployment of distributed solar from the utility perspective. The APS study was conducted in an open process with the participation of many stakeholders from within the solar industry, the business community, advocates, and the regulatory community.

In constructing the methodology for reviewing the benefits of the three distributed solar technologies discussed above, the study's authors focused on low, medium, and high penetration scenarios, with generating capacity as a percent of peak demand reaching 0.5%, 6.4%, and 14% respectively by 2025 (Arizona Public Service, 2010, Tables 5-3 and 5-4). Within these scenarios, the authors made a number of assumptions about PV capital cost reductions, the availability of federal tax credits, and the make-up of APS tariffs. The APS study also developed a target scenario that assumed APS would deploy solar technologies to achieve the greatest possible benefits. The target scenario included a general scenario and one in which all commercial PV used single-axis tracking.

The benefits identified in the APS study included reduction in T&D line losses, deferment of T&D capacity upgrades and additions, reduction in necessary equipment size within the distribution system, avoided electric generation capacity costs, avoided fixed operating costs, avoided energy purchases, and avoided fuel purchases. While labeled differently, this is a subset of the list used by the AE study, leaving off environmental benefits and the ability to provide a hedge on natural gas prices, as well as the four factors ultimately left out of the primary AE analysis (disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control).

After detailed modeling, the APS study found a range of benefits across the various penetration and target scenarios of approximately 7.9¢ to 14.1¢/kWh in 2008 dollars, without reference to a particular scenario (Arizona Public Service, 2010, p. xxii). Residential rates for APS customers as of December 2010 were just under 9.4¢/kWh, ramping up in stages during summer months to 17.4¢/kWh for higher energy usage. Assuming benefits have increased with inflation, the APS study appears to be inconclusive regarding whether there is a subsidy flowing from residential ratepayers to NEM participants (calculated benefits at the lower end of the reported range are less than costs). For demand-metered customers, it seems that benefits exceed costs substantially.

An APS review of this report stated that benefits identified in the APS study were based on locating facilities optimally and maintaining utility ownership and control of the installations, although the benefits of optimal siting are not broken out separately in the APS study. The most likely benefit of selective siting would be for individual distribution circuits. Most transmission and generation benefits would accrue regardless of the location of NEM systems. Reported distribution system benefits are only 0 to 0.31¢/kWh, implying that the impact of selective siting is relatively modest.

Discussion of APS Study

Two important aspects of the APS study directly affect the extent of the benefits it found, and explain the substantial difference from the AE study results.

First, virtually no capacity benefits were identified for the years prior to 2025 and even then, the capacity benefits were only significant in the high penetration case. The study notes that capacity pricing is rolled into energy prices used to calculate the energy benefit, and in that sense, there is a capacity value. However, by "capacity benefit" we are only referring to deferral or avoidance of new utility-built generation and T&D. The APS study's rationale for not attributing capacity benefits was that T&D and utility generation investments are "lumpy" so it would take a great deal of DG to have an impact on those investment decisions. (Arizona Public Service, 2010, p. 6-9). This view takes a primary advantage of PV—the ability to be installed incrementally—and gives it no value until output from the PV installation fully displaces a new utility generator. APS notes that its Integrated Resource Plan calls for no new construction for the next seven to eight years because it has sufficient capacity at present, but the PV installed over the next eight years could push the need for new construction out further and should be attributed some value. APS expects that peak demand will grow by 4,170 MW from 2010 to 2025. (Arizona Public Service, 2010, Table 5-6) and it is reasonable to assume that even a modest level of DG would defer some quantity of system level utility investments by a year or more, thereby saving ratepayers money by deferring investment in these lumpy assets. In conjunction with modest levels of demand response, as discussed later in this report, installed solar facilities could also provide APS with firm power, eliminating the need for at least some portion of its contemplated generation and T&D investments.

The APS study makes a jump from modest penetration levels in 2015 to high penetration in 2025 without analyzing impacts in between. Even the high scenario assumes only 63 MW of DG by 2015 (Arizona Public Service, 2010, Table 5-3), or roughly 0.7% of anticipated peak demand for APS in 2015 (Arizona Public Service, 2010, Table 5-4). By comparison, DG capacity in PG&E's service territory in California is more than 2% of PG&E's peak demand as of early 2011. While the APS study looks at 6.4% and 14% penetrations in 2025, it would have been interesting to present capacity benefits in the 2% to 5% range that are likely in earlier years.

The second significant deficiency in the APS study is that it does not consider the benefits at the optimal penetration level using the optimal orientation. Because the study is "forward looking" in so far as it is not assessing the impacts of a program as currently implemented, it would seem logical to have performed this analysis. Indeed, the study acknowledges that southwest facing modules or solar tracking will increase production per MW in the late afternoon, when APS experiences peak demand, and have a greater capacity benefit than a south facing array of the same size. However, the scenarios describing the benefits of DG under the low and medium penetrations do not appear to take the capacity benefits of deploying these optimally oriented arrays into consideration.

Interestingly, in the high penetration case, a solar tracking sensitivity analysis concludes that in 2025, tracking would shift the APS peak to a later hour, at which time the capacity benefit would be little more than it would be with a fixed array pointed south. However, this case envisions generating capacity of 1,677 MW (Arizona Public Service, 2010, Table 5-3), which would be 14.6% of peak demand. The analysis has thus skipped from a modest penetration of 0.7% (63 MW) in 2015 to a penetration of 14.6% in 2025 without looking at the optimal penetration that would occur in between. To its credit, the APS study does acknowledge that energy storage would increase the capacity value of solar energy systems, but it does not attempt to quantify the benefit.

Finally, the APS study did not attribute any environmental benefits to the utility or quantify natural gas hedging benefits as the AE study did. Inclusion of these benefits would have contributed to an overall valuation of the benefits to utility ratepayers from the solar resources modeled in the study. And like the AE study, the APS study did not attribute any value to the ability of solar generation to provide voltage and reactive power support or to provide disaster recovery benefits.

California's Cost-Benefit Methodology for Distributed Energy Resources

Starting in 2004 in Rulemaking (R.) 04-03-017, the California Public Utilities Commission (CPUC) embarked on an effort to develop a framework for valuing distributed energy resources. The overarching goal of the proceeding was to develop a methodology planners could use to compare demand-side resources in a consistent fashion across all resources—energy efficiency, renewable distributed generation, combined heat and power, etc. Efforts by numerous parties including renewable energy and combined heat and power advocates, CPUC staff, ratepayer advocates, and utilities to develop this methodology went on for a number of years and into successor distributed generation dockets R.06-03-008 and R.08-03-008. Stakeholders' efforts culminated in the issuance of Decision (D.) 09-08-026 on August 20, 2009.

In D.09-08-026, the CPUC established a methodology for valuing a wide range of distributed energy resources based on the approach used to value energy efficiency in California's Standard Practice Manual (SPM). In that vein, D.09-08-026 considers four tests described in the SPM for use in evaluating DG resources—the participant test, the rate payer impact (RIM) test, the program administrator (PA) test, and the total resource cost (TRC) test. Ultimately, the CPUC chose to use four tests—the participant test, the PA test, the TRC test, and the societal test—in evaluating DG resources. The societal test is very similar to the TRC test, but includes the impacts of externalities such as environmental costs/benefits, excludes tax benefits, and uses a different discount rate. Each of these tests views the costs and benefits of DG resources from different perspectives—the participating customer-generator (participant test), ratepayers generally (the RIM test), society (TRC and societal tests), and the program administrator, which in California is often the utility (the PA test).

Although D.09-08-026 does not require the use of the RIM test for a general evaluation of DG resources, the test is relevant to a discussion of the rate impacts of NEM because the RIM test attempts to compute bill and rate impacts due to changes in utility revenues and costs. D.09-08-026 identifies the following benefits within the RIM test—avoided T&D line losses, avoided energy and resource adequacy costs, T&D investment deferrals, environmental benefits, increased revenue from fuel transportation for natural gas-fired DG (not relevant for solar energy), and reliability benefits (ancillary benefits and volt-ampere reactive [var] support).

Unlike the AE and APS studies, the CPUC decision also identified costs, including net metering bill credits, program administration, reduced revenue from standby charge exemptions, lost revenue from non-bypassable charges, reduced T&D and non-fuel generation revenues, increased reliability costs for ancillary services and var support, cost of utility rebates or incentives, the cost of utility interconnection not charged to customer-generators, and increased utility fuel transportation costs for gas-fired DG (not relevant for solar energy).

Discussion of D.09-08-026

Inclusion of lost revenues must be handled very carefully in the context of NEM of intermittent resources such as solar and wind. In theory, the utility has a right to recover certain fixed costs under its standard tariffs, and NEM cuts into that expected recovery. However, great care must be taken to avoid double counting of costs. For instance, D.09-08-026 recognized that inclusion of lost standby charge revenue could result in double counting of lost T&D revenues, because standby charges developed in California were also designed to recover T&D expenses. Because both revenue streams would be recovering the same T&D expense, recovery of lost standby charge revenue along with recovery of lost T&D revenues could result in double counting of lost T&D revenues.

Additionally, practitioners must consider other factors when addressing lost revenue claims. First, utility standby charges are designed to recover the utility's cost of being constantly prepared to meet a customer's peak demand in the event that on-site generation is not functioning at the time of that peak demand. In the case of intermittent resources, it is a near certainty that generation will not be effective at some time during each billing cycle when the customer's demand nears the customer's peak demand. In other words, at those times, the customer's solar array is providing minimal generation to offset the customer's electricity consumption, and the customer will pay a demand charge based on almost all of the customer's peak consumption. For demand-metered customers in this situation, the demand charge resulting from their peak demand is already at or very close to their peak consumption, so the utility is not standing by, it is providing the necessary power and charging for it already. Claiming that preclusion from billing standby charges is a utility cost is effectively claiming that the utility can bill the customer twice for fixed costs, which obviously is not correct. Double counting would almost certainly occur if potential lost standby charge revenue is included as an additional cost of the NEM of intermittent resources.

Moreover, although residential and small commercial customers do not face demand charges, the variability in their relatively small loads due to renewable generation has not been shown to have any significant impacts on the grid or been shown to be potentially any different than customers without renewable generation who have significantly varying loads from one moment to the next. Accordingly, requiring that these customers pay standby charges would be discriminatory in the absence of a cost of service study showing a clear justification for such charges.

These are not abstract concerns. For example, when Southern California Edison (SCE) undertook a more detailed review of its standby charges in light of the diversity of standby customer load compared to regular retail load, SCE found that the diversity of standby customer load was imposing significantly less cost on the distribution system than its regular tariffed customers. Accordingly, SCE redesigned its standby charge rates by reducing demand charges when compared to regular tariff services. Looking at this change in reverse, prior to the change in demand charges, standby customers were significantly overcompensating SCE under its prior standby charges. It would be useful to see whether customer investment in renewable energy similarly results in a greater diversity in their load when compared to typical retail customers, and has a similarly less taxing impact on the grid.

In sum, inclusion of lost utility revenue related to standby charges has some logical appeal and merit, but care must be taken to avoid double counting. Moreover, standby charges and T&D charges designed to recover costs from ratepayers who have not invested in DG resources may overcompensate the utility in the absence of cost of service studies specific to DG customers, which would set these fees in that context. That is, calculating lost revenues based on these tariffs could overstate the amount of the utility's lost revenue.

California's Net Energy Metering Cost Effectiveness Evaluation

In late 2008, the CPUC commissioned Energy and Environmental Economics, Inc. to value the excess generation produced by net-metered systems for the state's three largest IOUs—Pacific Gas & Electric (PG&E), SCE, and San Diego Gas & Electric (SDG&E). The resulting study, Net Energy Metering (NEM) Cost Effectiveness Evaluation (Energy and Environmental Economics, Inc., 2010) (E3 study), was publicly issued in March 2010 (dated January 2010). The study delves into detail by utility, customer class, customer size, and location not seen in any other study.

E3 Study Overview

As part of its focus on the costs and benefits of net-metered solar generation from the utility perspective, the E3 study provides the country's first comprehensive look at the rate impacts of NEM, making it uniquely important in this report. Although it does not reference the RIM test discussed above, the E3 study relies heavily on the analysis performed in D.09-08-026. Because of that fact, despite the groundbreaking nature of the E3 study, many of the flaws and concerns discussed above are present in the E3 study.

The benefits of NEM provided in the E3 study are similar to those in the AE and APS studies. For the E3 study, they include avoided costs from avoided energy purchases, avoided generation capacity or resource adequacy, avoided line losses, avoided T&D capacity, avoided environmental compliance, avoided ancillary services, and avoided renewable energy purchases by the utilities under California's Renewable Portfolio Standard.

On the cost side of the equation, the study evaluated the cost of bill credits provided to NEM participants, administrative costs, and interconnection costs (under California law interconnection costs are not billed to NEM customers).

While the complexity of the analysis in the E3 study precludes a detailed discussion of the methodology here, one example highlights the comprehensive nature of the study. Recognizing that the impact of NEM will not be uniform for all customer-generators, the E3 study models the impacts in 1,253 distinct customer-groupings based on utility, customer type, facility sizing in relation to customer load, and location. (Energy and Environmental Economics, Inc., 2010, p. 29) The complexity of such an undertaking is daunting, but it is important to accurately reflect the timing, size, cost, and benefits of exported energy. Additionally, to further explore the impact of certain cost assumptions on the analysis, the E3 study includes a sensitivity analysis related to billing costs, T&D avoided costs, standby charges, and interconnection costs.

Overall, the E3 study finds that current rate impacts average just over a hundredth of a cent for every kWh purchased (0.011¢/kWh, Energy and Environmental Economics, Inc., 2010, Table 4). Delving more deeply into the average figure, the results for each utility were 0.018¢/kWh for PG&E, 0.0005¢/kWh for SCE, and 0.0009¢/kWh for SDG&E. These are truly small figures; utility rates often rise by a penny or more per kWh in a utility rate case, and the figures here are all less than a fiftieth of a cent.

Looking to the future, the E3 study finds that by 2020, 2,550 MW of net-metered solar generation will result in a 0.38% increase in utility rates or 0.064¢/kWh (Energy and Environmental Economics, Inc., 2010, Table 5). In 2020, 2,550 MW of generation would be 3.7% of forecast peak load of just over 60,898 MW for the three utilities. (California Energy Commission, December 2009, p. 51—adding coincident peak demands for PG&E, SCE, and SDG&E). Taking the facts provided here, for every 1% of solar generation, as a percentage of utility peak demand, the E3 study indicates a 0.1% impact on utility rates.

Discussion of the E3 Study

Although the E3 study concludes that NEM at the California IOUs entails a modest subsidy of customer-generators by other ratepayers, several assumptions drive that conclusion.

First, an important assumption made in the E3 study is that the rate impact of NEM is limited to the impact of exported energy. The study notes that customers can generate electricity without NEM, but would not be able to export. With this approach, rate impacts related to energy used on site at the time of generation are not impacts of NEM, they are impacts related to solar generation generally. The study notes that 243 customer-generators with a total of 43 MW of generating capacity do not export at all, and are excluded from the impact analysis entirely. (Energy and Environmental Economics, Inc., 2010, p. 14). While the E3 study does not say it, this approach implicitly assumes that without NEM in place to support customer-generators, customer-generators would have installed the same amount and type of generation, would not have changed their consumption patterns to make better use of their renewable energy investments, and, finally, that excess generation would be delivered to utilities for minimal compensation. This is not a likely outcome.

In the absence of NEM, there would still be federal and state incentives to install solar energy facilities along with the incentive of offsetting coincident customer load, but customer-generators would likely behave differently. On the one hand, some facilities might be sized smaller to reduce the amount of excess generation. Exported energy could still be sold at the utility's avoided cost in accordance with federal law, but that is less than retail rates, and customers could be expected to react to that lower payment. On the other hand, customers would be likely to try to better coordinate generation and consumption in the absence of NEM, to increase the percentage of generation used on site. For example, air conditioning equipment could be operated in conjunction with generation, cooling more at mid-day and less in the late afternoon. As well, customer-sited batteries could allow customers to synchronize inter-day generation and load for a modest additional investment.

It would be difficult to model generation and load in the absence of NEM, and it is understandable that the E3 study made the simplifying assumption that customers with solar energy facilities would not attempt to match generation and load in the absence of net metering. However, as a practical matter, the reported rate impact of NEM is probably overstated, because customer-generators would modify their behavior in the absence of an NEM program.

Second, it is important to recognize that the E3 study bases costs on the rates that utilities would have charged customer-generators, and California's IOUs have some of the highest residential rates in the country. For example, a residential customer exporting 1,000 kWh in a year will get a credit for 1,000 kWh from the customer's utility, which means the utility did not have the opportunity to sell that amount of energy to the customer for as much as 40¢/kWh. In many parts of the country, top residential rates are less than 10¢/kWh, and utilities' lost revenue from NEM is therefore much lower.

Additionally, the E3 study suffers from several deficiencies that, when looked at cumulatively, greatly decrease the value of the benefits from the energy provided by net-metered customers. Most importantly, the study finds that the utilities have limited need for additional capacity until 2015, so the study provides customer generation with limited credit for capacity value until after 2015. The E3 study values capacity starting at $28/kW/yr in 2008 and increases linearly to $141/kW/yr in 2015, then increases at a more modest pace to more than $200/kW/yr by 2036 (Energy and Environmental Economics, Inc., 2010, Appendix A, p. 15-16).

Broadly, this assumption implies that utility planning occurs without consideration of customer generation, and accordingly assigns a limited capacity value for customer-sited generation. This assumption simply does not square with current practice in California for a number of reasons. First, long-term resource planning in California does include customer-sited generation because the utilities' long-term resource acquisition plans rely on load forecasts based on historical loads that include customer-sited generation and anticipated future customer-sited generation. Second, the California Energy Commission recently denied an application to build the natural gas fired Chula Vista plant based partly on the fact that significant solar DG would be coming online. So both in theory and practice, customer-sited DG is being taken into account in long-term decision-making on the need for generating capacity.

Interestingly, the E3 study's valuation of the capacity benefit of NEM solar generation is considerably lower than the likely valuation of capacity for solar energy purchased by California utilities under long-term contracts. While still under consideration, it appears that the market price referent (MPR) will be used for these contracts (other than the contracts under the Renewable Auction Mechanism). The MPR is based on the total cost of generation for a natural gas combustion turbine, including capital costs, and thus incorporates capacity value. It has been argued that solar energy under contract has more value than NEM solar energy because there is no assurance that the latter will continue to operate. However, there is no reason to expect widespread decommissioning of NEM systems. Having paid to install their systems, NEM customers are unlikely to remove them and forgo utility bill savings, and there are very few instances of such actions to date. It seems reasonable to give NEM generation the same capacity credit accorded to solar energy purchased under long-term contracts.

To highlight the significance of this flaw in the study's methodology, an added capacity value of even a \$20/kW/yr increase, applied to 2,550 MW of solar generation, is \$51,000,000 per year—a significant added benefit that would negate much of the net cost per year of NEM in the E3 study. For other states and utilities attempting to value capacity, the lesson is that to properly determine capacity value, a base assumption should be that the generation was anticipated, or should have been anticipated, and its value should not be assessed after the utility has made its generation choices and has sufficient generation. At the margin, a prudent utility has sufficient capacity and there is limited value to adding more capacity.

The other important factor not considered in the E3 study is reactive power and voltage support, as discussed earlier in this report. D.09-08-026, identified var support as an NEM cost, presumably based on the assumption that fixed-voltage inverters on solar energy facilities might cause greater voltage fluctuations on the circuit. As discussed earlier, new technology and revised standards will allow inverters to provide adjustable voltage support and var control. While current utility infrastructure does not enable utilities' use of these functions, the implementation of smart grid with associated communications and controls enhancements offers the strong potential to turn this presently deemed cost into a future benefit.

Administrative costs are identified in the E3 study as well, based on reported utility costs. Monthly incremental administrative costs for residential net-metered customers are a reported \$18.31 for PG&E, but only \$3.02 for SCE and \$5.96 for SDG&E. (Energy and Environmental Economics, Inc., 2010, p. 40) As noted above, to further explore the impact certain cost assumptions have on the results, the study performed sensitivity analysis. As part of that analysis, the study took a closer look at administrative costs, including a sensitivity analysis based on no administrative cost (the base case accepts the PG&E cost). This sensitivity analysis resulted in a 27% decrease from the base case. This sensitivity analysis is reasonable to consider because, while in practice there is some minor administrative cost per customer, that cost is likely to drop with automation and high volume. An overstatement of \$12/mo for systems averaging 6 kW in PG&E's service territory is equivalent to roughly \$24/kW/yr, implying an added cost of roughly \$24,000,000 per year, which seems unreasonable.

Automation of billing to handle NEM over the long term is sensible as part of an overall update of utility billing software to support the move to a smart grid that supports distributed generation. A holistic view of the necessary changes to utility billing practices is also required to support investment in the smart grid. These changes include the need to accommodate NEM, demand response, advanced energy storage, vehicle electrification, and other necessary initiatives. All of these long-term policies have been identified as necessary to meet climate and environmental goals and therefore should not be viewed in isolation. In particular, smart metering has been justified based on traditional utility cost savings, and should allow administrative costs for NEM and other programs to drop to very low levels.

As noted earlier, it is critical to recognize that California IOUs have tiered rates as high as 40¢/kWh, so the lost-revenue cost to the California IOUs is two to five times higher than most utilities in the United States. In fact, the top rate at PG&E contemplated in the E3 study was 50¢/kWh, although that tier has since been eliminated.

Quantifying the Capacity Value of Solar

Because the capacity value for PV has been a particularly thorny issue in determining the value of solar resources for utilities, it is worthwhile to provide more discussion on this topic. For many utilities, peak demand typically occurs in the late afternoon. This fact is often cited as a key reason to dismiss the ability of solar to provide significant capacity benefits. However, depending on the actual hour of peak demand, modules can be oriented to the southwest to enable them to operate near their rated capacity in the late afternoon. Careful program design that encourages customers to orient their solar resources to meet a later system peak can address this concern. As discussed in the APS study, southwesterly oriented modules operate at more than two-thirds of rated capacity from 5:00 to 6:00 pm on a sunny summer day and at half of rated capacity from 6:00 to 7:00 pm. Moreover, modules pointed southwest are operating at only slightly less than their rated output between 3:00 and 4:00 pm, which was the peak load in California for 2008 (Self Generation Incentive Program Impact Report, 2008 revised).

The second challenge to solar energy's ability to provide capacity reliably is that cloud cover can dramatically impact an individual system's performance on short notice. In practice, the effect of cloud cover on a single solar energy system is not simultaneously felt across a whole region, and much of the variability is not even seen across a distribution circuit with multiple MW of interconnected generation. Perez et al. showed that just twenty systems over a limited service area will have a collective output with almost no variability on a partially cloudy day, despite the variability of each one of the systems individually (Perez et al., 2006). Likewise, researchers at Lawrence Berkeley National Laboratory recently calculated the smoothing effect of distributed solar power, finding that the relative aggregate variability of PV systems decreases with increased geographic diversity. That study showed aggregate variability over a 15-minute period is one-sixth of the variability of a single PV system, and over a one-hour period, it is one-third of the variability of a single PV system (Mills & Wiser, 2010).

Demand response or energy storage coupled with PV can play a role in meeting peak demand if peaking generation is not available at lesser cost. In a 2006 study, Perez et al. (Perez et al., 2006) analyzed the peak-month loads for three utilities and the coincidence of available solar generation. Stunningly, almost all of the loads above 90% of the utilities' peak load could be met with solar energy, with a minimal contribution provided by demand side management to fill in the gaps, as shown in Figure 3. In practical terms, these results show that solar energy is able to provide reliable energy peaking generation as needed with only a modest addition of demand side management.

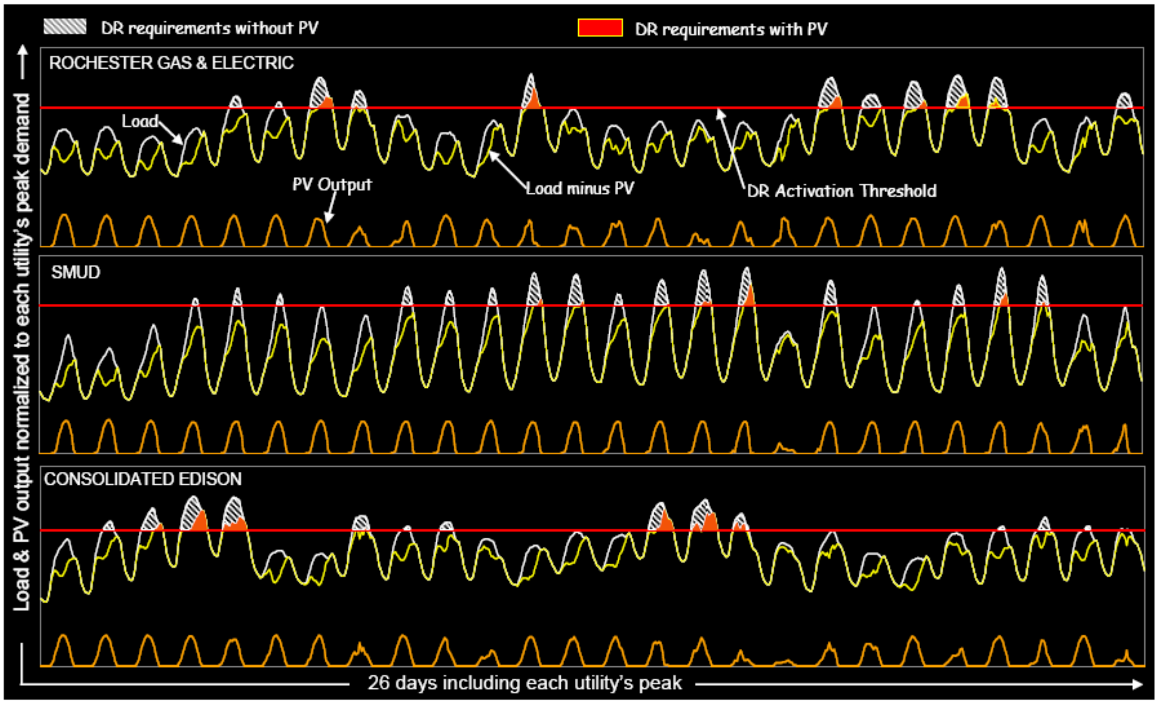

Figure 3. Integration of PV in demand response programs, using PV rated capacity of 20% of utility peak demand and showing the peak line at 90% of utility peak. Solid shading indicates periods of demand side management. Source: Perez et al., 2006.

In sum, research has demonstrated that many of the concerns that lead utility planners to discount the capacity value of PV can be addressed through program design, careful analysis of potential benefits from diffusion of solar resources, and coupling PV with demand response and energy storage. Based on these points, it is unreasonable to dismiss any capacity value to solar energy for a particular utility without considering these issues.

BEST PRACTICES IN VALUING NET ENERGY METERING

Given the recent efforts to value solar resources discussed in the "Relevant Studies" section, one can begin to see a relatively clear picture of the necessary inputs in a methodology to value solar resources.

Costs of Net Energy Metering from a Rate Impacts Perspective

On the cost side of the methodology, although the AE and APS studies did not attempt to develop a methodology for consideration of NEM costs, the two main inputs developed in D.09-08-026 for the RIM Test—NEM bill credits and program administration costs—are unsurprising and could be relatively noncontroversial if they are carefully developed.

As we have noted, careful calculation of NEM bill credits is important to avoid double counting of costs. CPUC D.09-08-026 suggests that costs should include reduced T&D and non-fuel generation revenues and lost potential revenues from a standby charge exemption. If NEM bill credits are determined by comparison of estimated bills before and after renewable resources are installed, "revenue losses" related to T&D charges and non-fuel generation revenues are already included. Moreover, customers who face demand charges based on maximum demand during the billing period could see little or no change in their demand charges, and thus would still be paying the T&D and non-fuel generation costs. For these reasons, inclusion of an additional input to measure T&D and non-fuel generation charges not collected by the utility due to NEM of solar and wind facilities is almost certainly double counting of this potential "lost revenue."

Depending on how standby charge tariffs are actually implemented by a particular utility, calculating the potential lost revenues from a standby charge exemption would double count T&D charges again. Inclusion of lost standby charges is also troublesome because standby charges have usually not been developed for intermittent DG resources and, therefore, are not based on the cost of serving these particular customers. To its credit, the E3 study considered this "lost revenue" in a sensitivity analysis, but did not consider it in the base case.

Caution concerning program administration costs is also warranted. While it might be intuitive to include the actual costs the utility estimates it has incurred in administering its NEM program, it is clear from the E3 study that critical review is necessary. As discussed in the prior section, self-reported administrative costs at PG&E were nearly quintuple the costs reported by SCE and SDG&E with no explanation for this disparity. While some variation in costs is reasonable, a cost spread of this magnitude should raise concern and be justified before inclusion in any cost-benefit analysis. Moreover, as utilities begin to implement billing system updates to handle smart meters, demand response/control functions, and other emerging policies, those systems should be designed to handle NEM more efficiently, and the incremental costs of NEM should decline to slightly more than zero.

Benefits of Net Energy Metering from a Rate Impacts Perspective

On the benefits side of the equation, each study discussed in this report finds that avoided T&D line losses, avoided capacity and energy purchase costs, and avoided T&D investment deferrals should be included as benefits (though the studies did not agree on how to account for the benefits). Inclusion of these benefits in a methodology to assess the possible rate impacts of NEM should be relatively noncontroversial given their consistent identification as benefits of customer investment in renewable energy resources. Avoided line losses stem from locating the generation source on site, which allows line losses due to transmission from distant generation sources to load to be almost completely avoided (there are very modest losses associated with excess generation stepping up to utility line voltage then back down when used nearby on the same circuit). Avoided capacity and energy purchase costs stem from the reduction in on-site customer load and export of excess energy. T&D investment deferrals stem from decreased customer load at the feeder, substation, and transmission levels, and can include deferrals of investment and postponing of investment in T&D upgrades. Care should be taken to ensure evaluation of T&D investment deferrals includes not only the deferral of capacity investment but also equipment and operations and maintenance, as both the APS study and D.09-08-026 recognize these value streams.

Moreover, both the AE study and the E3 study recognize that renewable resources can provide environmental benefits due to avoided emissions from non-renewable energy sources. These benefits are a direct consequence of the investment by customers in generation sources that emit few or no pollutants during their production of energy. While the AE study and E3 study took different approaches to valuing this benefit, given regulatory frameworks in place for the measurement of NO_x, SO_x, and particulate matter, and efforts to regulate CO_2, assessment of the environmental benefits of renewable resources should not be excluded as a benefit. The ability to mitigate carbon regulatory risk is particularly valuable. The CPUC Self Generation Incentive Program Eight-Year Impact Evaluation Revised Final Report (Itron, Inc., 2009) finds that PV was able to mitigate approximately 0.58 tons CO_2 per MWh. Given forecasts of future carbon prices in the range of $15 to $45 per ton on a levelized basis between 2013 and 2030, this would suggest a value of approximately $9 to 26/MWh in avoided carbon on a levelized basis. (Schlissel et al., 2008)

Additionally, consideration should be given to the possible benefits customer-sited renewable resources will have on a utility's obligations to purchase renewable energy to meet state mandates as discussed in D.09-08-026. For example, because the California Renewable Portfolio Standard bases each utility's compliance obligation on retail sales, utilities will be able to avoid purchases of renewable generation they might have otherwise been required to purchase because customer-sited generation lowers a utility's retail sales. For this reason, D.09-08-026 finds that a typical avoided cost methodology might not fully capture the benefits of customer-sited renewable resources in avoiding renewable generation additions by utilities to meet their RPS obligations. States like Arizona and Colorado with similar RPS obligations should take care to ensure this benefit is appropriately assessed in their cost benefit methodology.

The AE study and D.09-08-026 also recognized that customer investment in renewable energy resources could have significant impacts on the natural gas market. The AE study identified the ability of PV to act as a hedge on natural gas price increases, and D.09-08-026 recognized that customer investment in renewable energy could decrease the demand for natural gas and thereby lower the market price of natural gas for all participants. Unfortunately, it concluded that the impact is too small and too difficult to discern at current DG penetration levels.

The conclusion that renewable energy has no impact on natural gas prices is not supported by research. A Lawrence Berkeley National Laboratory study (Wiser, Bolinger, & St. Clair, 2005) provides a detailed review of studies assessing this benefit. These studies show that the price impacts in terms of $/MWh of renewable energy additions are significant, ranging from $10/MWh to $65/MWh nationally. Regional impacts were also evaluated. For example, the Lawrence Berkeley study found the impact of approximately $5/MWh within California. Similarly, the price hedge for natural gas was estimated in the California Energy Commission's 2007 Integrated Energy Policy Report at approximately $12/MWh. Given many utilities' substantial and increasing reliance on natural gas fired generation and consumer level consumption of natural gas, natural gas price impacts should not be ignored when estimating the rate impacts of NEM. Each of these benefits are significant and well documented and, therefore, worthy of inclusion as a benefit of customer-sited investment in renewable energy.

Regarding reliability, D.09-08-026 addressed only one part of the likely benefit of DG and arbitrarily set the value of other reliability benefits at zero. The decision concluded that demand reductions due to DG resources are likely to lead to the same reliability benefits that result from energy efficiency measures and the existing methodology to calculate that impact should be used for the present time. However, it only acknowledged that DG has the potential to provide ancillary services and var support. This ability has been widely acknowledged for inverter-based systems, although output voltage is typically preset rather than being reactive to utility grid voltage, so the ability to provide support is not used at present. However, this ability is very likely to be tapped, at least for larger solar facilities, and could add significant value. Even more importantly, the AE study properly noted that DG has the potential to provide backup power to both critical need customers and typical utility customers. The AE study placed a very high value on this functionality and it seems that some estimate should be made of this value. D.09-08-026 simply set var support and backup power values at zero, but properly directed that those values should be estimated.

Based on the three solar valuation studies reported here, best practices in developing a methodology for evaluating the rate impacts of net metering counsel for including the inputs noted in Table 2.

TABLE 2

Necessary Costs and Benefits Inputs in a Methodology for Evaluating the Rate Impacts of Net Energy Metering

Benefits to the Utility	Costs to the Utility
Avoided Energy Purchases	NEM Bill Credits
Avoided T&D Line Losses	Program Administration
Avoided Capacity Purchases	
Avoided T&D Investments and O&M	
Environmental Benefits—NO_x, SO_x, PM, & CO_2	
Natural Gas Market Price Impacts	
Avoided RPS Generation Purchases	
Reliability Benefits	

CONCLUSION

To date, views concerning the possible rate impacts of NEM programs have driven many of the policy deviations from best practices in NEM in many states. However, very little rigorous analysis of the relative costs and benefits of NEM has been done. In reviewing the major net metering and PV cost-benefit studies performed to date, we identified the benefits noted at the end of the previous section as essential for inclusion in any study of the possible NEM rate impacts.

On the cost side of the analysis, the three studies provide guidance as well. The primary cost of NEM is the utility's lost revenue from utility ratepayers, equal to what ratepayers would have paid had NEM not been available. As the E3 study did, we recommend that the lost ratepayer revenue only focus on the bill impacts directly attributable to NEM (i.e. directly attributable to providing value to excess generation). The lost revenue due to NEM should not be based on all production from customer-sited generation, because a customer can install a system to offset their energy needs without an NEM program in place. While simplifying assumptions—that the amount of generation installed would not change or other measures would not be taken to store excess energy for later consumption, for example—are necessary, given the relatively small percentage of generation that is actually net metered, such simplifications seem reasonable.

In addition, utility administrative costs should be included, as discussed in the E3 study. However, the variance in administrative costs among the three California utilities surveyed indicates a need to review cost claims carefully. An assumption regarding future administrative cost reductions per kWh should be included to account for automation of processes. Other costs can be considered based on any unique features of a state's net metering program, but they should be carefully considered to ensure they actually stem from a state's decision to allow net metering versus a decision to allow customer-sited generation as a general matter.

E3's pioneering work quantifying the benefits and costs of California's NEM program highlights the fact that further research is necessary to arrive at consensus on the appropriate methodology for quantifying these benefits and costs. However, the inclusion of the benefits listed at the end of the prior section should be relatively noncontroversial in most instances. As noted earlier, the cost-benefit analysis is utility-specific, and some utilities may realize little benefit from one or more of the items noted in Table 2. A utility in a state without an RPS will not have any savings associated with avoided RPS purchases. A winter-peaking utility will not have a substantial capacity benefit.

Based on the review undertaken in this report, it would be difficult to conclude that nonparticipating customers subsidize demand-metered customers with NEM facilities. The cost to the utility of demand-metered customers deploying NEM is the loss of energy charges, but those energy charges are based on the variable costs that the utility avoids by not having to provide the energy that is instead generated on site. The administrative cost in the long run should drop to almost nothing per kWh, and the non-energy benefits discussed here will still be provided. It appears that demand-metered customers with NEM facilities will typically provide a net benefit to nonparticipating customers.

For customers with bundled rates, such as residential customers, whether or not there is a net benefit will depend on utility-specific costs and benefits.

RECOMMENDATIONS

We recommend that utility regulators wishing to determine the NEM rate impact for specific utilities use the guidelines provided in this report. In particular, we recommend that:

- Studies comparing the costs and benefits of NEM include the costs and benefit inputs identified in Table 2 above.
- As part of this effort, none of the benefits identified in Table 2 should arbitrarily be set to zero based on unsupported assumptions.
- Capacity benefits associated with deferral of utility generation and T&D facilities should be modeled under a long-term framework to ensure that the value of PV to defer these resources under a long-term planning framework is properly captured.
- Assessment of the costs and benefits of net metering should be based only on exported energy, not the entire production of the facility.
- Program administrative costs should be based on a long-term assessment of costs based on the expectation that updating utility billing software to accommodate and support grid-modernization efforts, which include net metering, will be necessary.

At the earliest stages of a NEM program, the cost of such studies may be greater than any net costs or net benefits themselves, and regulators may understandably be hesitant to undertake studies prior to significant NEM deployment. The results discussed in this report should give regulators confidence that rate impacts at the earliest stages will be negligible and need not be a concern that leads to restrictive NEM policy.

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Appendix A

Summary of Costs and Benefits Inputs Used in Three Solar Valuation Studies

	Austin Energy Study	APS Study	CPUC E3 NEM Study
BENEFITS			
Energy production value	X	X	X
Generation capacity value	X	X	X
T&D deferrals	X	X	X
Reduced transformer losses	X	X	X
Reduced line losses	X	X	X
Environmental benefits	X		
Natural gas price hedge*	X	X	
Blackout prevention*	X		
Emergency utility dispatch*	X		
Managing load uncertainty*	X		
Retail price hedge*	X		
Reactive power control*	X		
Reduced distribution system size		X	
Avoided fixed operating costs		X	
Avoided environmental compliance			X
Avoided ancillary services			X
COSTS			
Net metering bill credits			X
Program administration**			X
Reduced standby charge revenue***			X
Costs of interconnection not charged***			X

* These benefits were not quantified in the Austin study. The study found that the benefits were real and quantifiable, but there was insufficient data to assign them a value for Austin Energy.

** Because of data problems with utility reported billing costs, these costs were also included in a sensitivity analysis.

*** These benefits were included as sensitivity analysis.

ACRONYMS

AE	Austin Energy
APS	Arizona Public Service
CPUC	California Public Utilities Commission
D.	decision
DG	distributed generation
IOU	investor owned utility
kW	kilowatt
kWh	kilowatt-hour
MPR	market price referent
MW	megawatt
NEM	net energy metering
NNEC	Network for New Energy Choices
PG&E	Pacific Gas & Electric
PA	program administrator
PV	photovoltaic
R.	rulemaking
RIM	ratepayer impact
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPM	California's Standard Practice Manual
TRC	total resource cost
T&D	transmission and distribution
var	volt-ampere reactive

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